6560-50-PXXXX-XX-X

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 49

[EPA-R08-OAR-2015-0709; FRL-XXXX-XX-OAR]

RIN 2008-AA02

Approval and Promulgation of Federal Implementation Plan for Existing Oil and Natural Gas Well Production Facilities; Uintah and Ouray Indian Reservation in Utah

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing to promulgate a Federal Implementation Plan (FIP) to regulate volatile organic compound (VOC) emissions from existing oil and natural gas production facilities on Indian country lands within the Uintah and Ouray (U&O) Indian Reservation in Utah. The U&O Reservation is within the physiographic region known as the Uinta Basin. The requirements in this proposed FIP are intended to address two concerns: (1) degraded air quality in the Uinta Basin due to ozone; and (2) regulatory requirements that are inconsistent between Indian country and State of Utah jurisdictions. Air quality data and studies in the Uinta Basin show wintertime ozone levels above the National Ambient Air Quality Standards (NAAQS) for ozone due in large part to VOC emissions from existing oil and natural gas production facilities in the basin. On the Indian country lands within the U&O

Reservation, there are currently no requirements to reduce VOC emissions from minor oil and natural gas production facilities, while such facilities in areas under the State of Utah's jurisdiction must comply with minor source permits that require VOC controls and with Utah regulations specific to oil and natural gas emission sources. Under the proposed FIP, owners and operators of existing oil and natural gas production facilities on the Indian country lands within the U&O Reservation will be required to reduce VOC emissions from sources in the production segment of the oil and natural gas sector. We are proposing to find that it is necessary and appropriate to promulgate a FIP that includes basic VOC control regulations for the consistent protection of air quality in communities in and adjacent to the Reservation, where existing oil and natural gas production operations have contributed to exceedances of the ozone NAAQS. The proposed FIP will give the regulated community certainty that requirements will be consistent across jurisdictional boundaries, because they are consistent with Utah's regulations that are applicable to existing non-Indian-country oil and natural gas sources. Unless and until replaced by a Tribal Implementation Plan, the proposed FIP will be implemented by the EPA or by the Ute Indian Tribe, if delegated authority by the EPA.

DATES: Comments must be received on or before **[INSERT DATE 60 DAYS AFTER PUBLICATION IN THE FEDERAL REGISTER]**. Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your comments on or before **[INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

Public Hearing: The EPA will hold a public hearing on [INSERT DATE] on the proposed FIP. The hearing will be held to accept oral comments on the proposed FIP. The hearing will start at [INSERT TIME] local time and continue until [INSERT TIME] or until everyone has had a chance to speak. Additionally, an evening session will be held from 6:00 p.m. until 8:00 p.m. The hearing sessions will be held at the [INSERT LOCATION, ADDRESS, & PHONE NUMBER].

ADDRESSES: Submit your comments, identified by Docket ID No. EPA-R08-OAR-2015-0709, by one of the following methods:

- http://www.regulations.gov. Follow the on-line instructions for submitting comments.
- Mail: Carl Daly, Director, Air Program, U.S. EPA, Region 8, Mail code 8P-AR, 1595 Wynkoop St., Denver, CO 80202-1129.
- Hand Delivery: Carl Daly, Director, Air Program, U.S. Environmental Protection Agency (EPA), Region 8, Mail code 8P-AR, 1595 Wynkoop Street, Denver, Colorado 80202-1129. Such deliveries are only accepted Monday through Friday, 8:00 a.m. to 4:30 p.m., excluding Federal holidays. Special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA-R08-OAR-2015-0709. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at http://www.regulations.gov, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information for which disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through http://www.regulations.gov. The http://www.regulations.gov Web site is an "anonymous access" system, which means that the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD-ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at www.epa.gov/epahome/dockets.htm.

Docket: All documents in the docket are listed in the http://www.regulations.gov index. In some instances we reference documents from the dockets for other rulemakings. For this proposed rule, we have incorporated by reference Docket ID No. EPA–HQ–OAR–2010–0505[1], Docket ID EPA-R08-OAR-2012-0479

[1] Proposed Rule: Emission Standards for New and Modified Sources, 80 FR 56593 (Sep.

[2] and Docket ID No. EPA–HQ–OAR–2015–0216[3] into Docket ID EPA-R08-OAR-2015-0709. Although listed in the index, some information is not publicly available, e.g., CBI or other information for which disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly-available docket materials are available either electronically at http://www.regulations.gov or in hard copy at the following locations: Air Program, U.S. EPA, Region 8, Mail code 8P-AR, 1595 Wynkoop Street, Denver, Colorado 80202-1129; and Energy and Minerals Department, Ute Indian Tribe, P.O. Box 70, Fort Duchesne, Utah 84026-0190. The EPA requests that if at all possible, you contact the persons listed in the **FOR FURTHER INFORMATION CONTACT** section if you wish to view the hard copy of the docket. You may view the hard copy of the docket Monday through Friday, 8:00 a.m. to 4:00 p.m., excluding Federal holidays.

FOR FURTHER INFORMATION CONTACT: Deirdre Rothery, U.S. EPA, Region 8, Air Program, Mail Code 8P-AR, 1595 Wynkoop Street, Denver, Colorado 80202-1129, (303) 312-6431, rothery.deirdre@epa.gov.

SUPPLEMENTARY INFORMATION:

Definitions

18, 2015); docket available at http://www.regulations.gov.

[2] Final Rule: Federal Implementation Plan for Oil and Natural Gas Well Production Facilities, Fort Berthold Indian Reservation, North Dakota, 78 FR 17835 (March 22, 2013); docket available at http://www.regulations.gov.

[3] Notice of Availability: Draft control Techniques Guidelines for the Oil and Natural Gas Industry, 80 FR 56577 (Sep. 18, 2015); docket available at http://www.regulations.gov.

APA: the Administrative Procedure Act.

Act or CAA: Clean Air Act, unless the context indicates otherwise.

BTU: British Thermal Unit.

CBI: Confidential Business Information.

CDPHE: Colorado Department of Public Health and Environment's Air Pollution Control Division.

CO: carbon monoxide.

EPA, we, us or our mean or refer to the United States Environmental Protection Agency.

Reservation means or refers to the Indian country lands within the Uintah and Ouray Indian Reservation.

FIP: Federal Implementation Plan.

GOR: gas-to-oil ratio.

HAP: hazardous air pollutant.

LACT: lease automatic custody transfer.

MDEQ: Montana Department of Environmental Quality's Air Resources Management Bureau.

NAAQS: National Ambient Air Quality Standards.

NAICS: North American Industry Classification System.

NDDoH: North Dakota Department of Health's Division of Air Quality.

NESHAP: National Emission Standards for Hazardous Air Pollutants.

NMED: New Mexico Environment Department's Air Quality Bureau.

NO_x: nitrogen oxides.

NO_2: nitrogen dioxide.

NSPS: New Source Performance Standards.

NSR: New Source Review.

ODEQ: Oklahoma Department of Environmental Quality's Air Quality Division.

PM: particulate matter.

PSD: Prevention of Significant Deterioration.

PTE: potential to emit.

RCT: Railroad Commission of Texas, Oil and Gas Division.

SCADA: Supervisory Control and Data Acquisition.

SIP: State Implementation Plan.

SO_2: sulfur dioxide.

TAR: the Tribal Authority Rule.

TAS: treatment in the same manner as a state.

TIP: Tribal Implementation Plan.

UDEQ: Utah Department of Environmental Quality's Division of Air Quality.

U&O Reservation or the Reservation: Uintah & Ouray Indian Reservation.

VOC: volatile organic compound(s).

VRU: vapor recovery unit.

<u>WDEQ</u>: Wyoming Department of Environmental Quality's Air Quality Division.

<u>The information presented in this preamble is organized as follows</u>:

D. Unfunded Mandates Reform Act (UMRA)
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments
G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act (NTTAA)
J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

I. General Information

A. What entities are potentially affected by this proposal?

Entities potentially affected by this proposal consist of existing sources, as defined in this action, that are in the production segment of the oil and natural gas sector and are on Indian country[4] lands within the U&O Reservation.[5] All of the Ute Indian

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[4] Indian country is defined at 18 U.S.C. §1151 as: (a) all land within the limits of any Indian reservation under the jurisdiction of the United States Government, notwithstanding the issuance of any patent, and, including rights-of-way running through the reservation, (b) all dependent Indian communities within the borders of the United States whether within the original or subsequently acquired territory thereof, and whether within or without the limits of a state, and (c) all Indian allotments, the Indian titles to which have not been extinguished, including rights-of-way running through the same.
[5] The U&O Reservation was established for the Ute Indian Tribe under Executive Order in October 3, 1861, as confirmed by the Act of May 5, 1864, 13 Stat. 63, and Executive Order of January 5,1882, then subject to additional Congressional enactments, formally reorganized (1937 Constitution and By-Laws of the Ute Indian Tribe of the Uintah and Ouray Reservation) and enlarged through the Hill Creek Extension Act of 1948 (62 Stat. 72). The Reservation has been addressed in several federal court decisions, including *Ute Indian Tribe v. Utah*, 521 F. Supp. 1072, 1155 (D. Utah 1981); *Ute Indian Tribe v. Utah*, 716 F.2d 1298 (10th Cir. 1983); *Ute Indian Tribe v. Utah*, 773 F.2d 1087 (10th Cir. 1985) (en banc), *cert. denied*, 479 U.S. 994 (1986); *Hagen v. Utah*, 510 U.S. 399 (1994); *Ute Indian Tribe v. Utah*, 935 F. Supp. 1473 (D. Utah 1996); *Ute Indian Tribe v. Utah*, 114 F.3d 1513 (10th Cir. 1997), *cert. denied*, 522 U.S. 1107 (1998); and *Ute Indian Tribe*

Tribe Indian country lands of which EPA is aware are located within the exterior boundaries of the Reservation and this FIP will apply to all such lands. To the extent that there are Ute Indian Tribe dependent Indian communities under 18 U.S.C. 1151(b) or allotted lands under 18 U.S.C. 1151(c) that are located outside the exterior boundaries of the Reservation, those lands will not be covered by this FIP unless the EPA or the Tribe demonstrates that the Tribe has jurisdiction over the area.[6] In addition, this proposed rule will not apply to any sources on non-Indian-country lands, including any non-Indian-country lands within the exterior boundaries of the Reservation.

TABLE 1 – SOURCE CATEGORIES AFFECTED BY THIS PROPOSED ACTION

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v. Utah, 790 F.3d 1000 (10th Cir. 2015), *cert. denied*, 2016 U.S. LEXIS 1969 (U.S. Mar. 21, 2016). As a result of this line of cases, there are some non-Indian-country lands within the exterior boundaries of the Uintah and Ouray Indian Reservation.

[6] Under the CAA, lands held in trust for the use of an Indian tribe are reservation lands within the definition at 18 U.S.C. § 1151(a), regardless of whether the land is formally designated as a reservation. *See* Indian Tribes: Air Quality Planning and Management, 63 Fed. Reg. 7254, 7258 (1998) ("Tribal Authority Rule"); *Arizona Pub. Serv. Co. v. EPA*, 211 F.3d 1280, 1285-86 (D.C. Cir. 2000). EPA's references in this FIP to Indian country lands within the exterior boundaries of the U&O Reservation include any such tribal trust lands that may be acquired by the Ute Indian Tribe.

In 2014, the U.S. Court of Appeals for the D.C. Circuit addressed EPA's authority to promulgate a FIP establishing certain CAA permitting programs in Indian country. *Oklahoma Dept. of Environmental Quality v. EPA*, 740 F. 3d 185 (D.C. Cir. 2014). In that case, the court recognized EPA's authority to promulgate a FIP to directly administer CAA programs on Indian reservations, but invalidated the FIP at issue as applied to non-reservation areas of Indian country in the absence of a demonstration of an Indian tribe's jurisdiction over such non-reservation area. Because the current proposed rule would apply only on Indian country lands that are within the exterior boundaries of the Uintah and Ouray Reservation, *i.e.*, on Reservation lands, it is unaffected by the *Oklahoma* court decision.

Industry Category	NAICS Code	Examples of Regulated Entities/ Description of Industry Category
Oil and Gas Production/Operations	21111	Exploration for crude petroleum and natural gas; drilling, completing, and equipping wells; operation of separators, emulsion breakers, desilting equipment, and field gathering lines for crude petroleum and natural gas; and all other activities in the preparation of oil and gas up to the point of shipment from the producing property Production of crude petroleum, the mining and extraction of oil from oil shale and oil sands, the production of natural gas, sulfur recovery from natural gas, and the recovery of hydrocarbon liquids from oil and gas field gases
Crude Petroleum and Natural Gas Extraction	211111	Exploration, development and/or the production of petroleum or natural gas from wells in which the hydrocarbons will initially flow or can be produced using normal pumping techniques or production of crude petroleum from surface shales or tar sands or from reservoirs in which the hydrocarbons are semisolids
Natural Gas Liquid Extraction	211112	Recovery of liquid

		hydrocarbons from oil and gas field gases; and sulfur recovery from natural gas
Drilling Oil and Gas Wells	213111	Drilling oil and gas wells for others on a contract or fee basis, including spudding in, drilling in, redrilling, and directional drilling
Support Activities for Oil and Gas Operations	213112	Performing support activities on a contract or fee basis for oil and gas operations (except site preparation and related construction activities) such as exploration (except geophysical surveying and mapping); excavating slush pits and cellars, well surveying; running, cutting, and pulling casings, tubes, and rods; cementing wells, shooting wells; perforating well casings; acidizing and chemically treating wells; and cleaning out, bailing, and swabbing wells
Engines (Spark Ignition and Compression Ignition) for Electric Power Generation	2211**	Provision of electric power to support oil and natural gas production where access to the electric grid is unavailable.

This list is not intended to be exhaustive, but rather provides a guide for readers regarding entities potentially affected by this action. To determine whether your facility could be affected by this action, you should examine the proposed FIP applicability criteria in section 49.4169. If you have any questions regarding the applicability of this action to a particular entity, contact the appropriate person listed in the **FOR FURTHER INFORMATION CONTACT** section.

B. What should I consider as I prepare my comments to the EPA?

Submitting CBI. Do not submit this information to the EPA through regulations.gov or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD ROM that you mail to the EPA, mark the outside of the disk or CD ROM as CBI and then identify electronically within the disk or CD ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. Send or deliver information identified as CBI only to the following address: Ms. Tiffany Purifoy, c/o OAQPS Document Control Officer (Room C404-02), U.S. EPA, Research Triangle Park, North Carolina 27711, and Attention Docket ID No. EPA-R08-OAR-2015-0709.

Coordination of Comments on Proposed Action Affecting Existing Oil and Natural Gas Production Facilities on the Uintah and Ouray Indian Reservation. The EPA is proposing this rulemaking that will affect existing oil and natural gas production facilities that operate on Indian country lands within the Uintah and Ouray Indian Reservation in Utah. We welcome comments on this proposed action. To help us respond more efficiently to public comments on this proposal, we request that commenters submit comments addressing the "FIP for Existing Oil and Natural Gas Production Facilities on the Uintah and Ouray Indian Reservation in Utah" proposed on [**INSERT DATE OF PUBLICATION**], to Docket ID No. EPA-R08-OAR-2015-0709. Comments submitted to Docket EPA-R08-OAR-2015-0709 will be part of the official record for this proposed rulemaking.

Docket. The docket number for this action is EPA-R08-OAR-2015-0709.

Preparing Comments. When submitting comments, remember to:

- Identify the rulemaking by docket number and other identifying information (subject heading, Federal Register date and page number).
- Respond to specific questions and link comments to specific CFR references when appropriate.
- Explain why you agree or disagree and suggest alternatives. Include specific regulatory text that implements your requested changes.
- Explain technical information and/or data that you used to as the basis of your

comment and provide references to the supporting information.

- If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.
- Provide specific examples to illustrate your concerns and suggest alternatives.
- Explain your views as clearly as possible, avoiding the use of profanity or personal threats.
- Make sure to submit your comments by the comment period deadline identified.

C. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this proposal will also be available on the Internet. After signature, a copy of this notice will be posted at: http://www3.epa.gov/airquality/oilandgas/actions.html (Oil and Natural Gas Air Pollution Standards Regulatory Actions page).

II. Purpose

A. This Action

In this action, we are proposing a Reservation-specific FIP to establish enforceable control requirements for reducing VOC emissions from existing oil and natural gas production activities on the U&O Reservation. Studies of ozone air quality in the Uinta Basin, where ambient ozone levels are high and exceed the ozone health standard, have found that ozone production in the area is sensitive to reductions in VOC emissions, but may be relatively insensitive to reductions in NO_X emissions.[7] Therefore, in developing this rule, we have concentrated on determining the most effective control requirements to reduce VOC emissions from existing minor oil and natural gas production sources. This proposed Reservation-specific FIP is consistent with the approach that the EPA articulated in the September 18, 2015, proposed Federal Implementation Plan for Managing Air Emissions from True Minor Sources Engaged in Oil and Natural Gas Production in Indian Country[8] that would address new true minor oil and natural production activities. In the preamble to that proposed rule, we indicated that the most appropriate means for addressing air quality concerns on specific reservations and the impacts from existing sources is through area- or reservation-specific FIPs and not through the national FIP. This action is consistent with that approach.

In this FIP, we are proposing to require owners and operators of existing minor oil and natural gas production sources on Indian country lands within the U&O Reservation in the Uinta Basin[9] to reduce VOC emissions from crude oil, condensate, produced water

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[7] Utah DEQ: Uinta Basin: Ozone: Overview Web page with reports on Uinta Basin Ozone Studies 2011 to 2014 field studies: http://www.deq.utah.gov/locations/U/uintahbasin/ozone/overview.htm, accessed March 8, 2006. Detailed discussion of the studies is in the technical support document, which can be viewed in the docket for this rulemaking (Docket ID No. EPA-R08-OAR-2015-0709).

[8] 80 FR 56554 (Sep. 18, 2015) (Oil and Natural Gas Production Indian Country FIP).

[9] The Western Regional Air Partnership (WRAP) defines the Uinta Basin as wholly including the counties of Carbon, Duchesne, Emery, Grand, Uintah, and Wasatch in Utah, see O&G Emissions Workgroup: Phase III Inventory, Uinta Basin Reports, 2012 Mid-Term Projection Technical Memo, "Development of 2012 Oil and Gas Emissions Projections for the Uinta Basin," March 25, 2009, available at http://www.wrapair2.org/Phase III.aspx, accessed November 30, 2015. EPA's Greenhouse Gas Reporting Program – Subpart W, covering the Petroleum and Natural

storage tanks, glycol dehydrators, pneumatic pumps, pneumatic controllers, tanker truck loading and unloading; and fugitive emissions from well sites and gathering and boosting compressor stations. Oil and natural gas production facilities may also include other VOC-emitting units or activities, such as compressors, two- and three-phase separators, heater treaters, gas well liquids unloading, turbines, and reciprocating internal combustion engines; this rule does not apply to those types of equipment. This rule also does not apply to new or modified sources that commence construction after the effective date of the final rule. It is expected that new and modified sources will be regulated under the New Source Performance Standards (NSPS) for the Oil and Natural Gas Sector at 40 CFR Part 60, subpart OOOO, proposed subpart OOOO revisions and proposed subpart OOOOa[10], the proposed revisions to the Federal Minor New Source Review Program in Indian Country at 40 CFR Part 49 (Federal Indian Country Minor NSR Program or Rule)[11], and the proposed Oil and Natural Gas Production Indian Country FIP. If we later

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Gas Systems, defines the Uinta Basin as the counties of Carbon, Daggett, Duchesne, Uintah and Wasatch. For the purposes of this rulemaking, the EPA defines the Uinta Basin consistent with the WRAP's definition.

[10] NSPS OOOO was originally published at 77 FR 49490(Aug. 16, 2012), with revisions on September 23, 2013 (78 FR 48416), December 31, 2014 (79 FR 79018), and August 12, 2015 (80 FR 48262). Additional revisions, including the addition of subpart OOOOa, were proposed in the Federal Register on September 18, 2015 (80 FR 56593). Information on these rulemakings is available at http://www3.epa.gov/airquality/oilandgas/actions.html, accessed October 14, 2015. All references to the proposed revisions assume the primary requirements will be finalized as proposed. We expect the revisions to be finalized by early summer 2016.

[11] Review of New Sources and Modifications in Indian Country, 76 FR 38748 (July 1, 2011), available at http://www.gpo.gov/fdsys/pkg/FR-2011-07-01/pdf/2011-14981.pdf, accessed October 14, 2015.

determine that there is a need for further emission reductions of VOC or other pollutants at the existing or new or modified oil and natural gas production facilities, we may propose an additional FIP or propose to supplement this FIP.

B. Purpose of the Proposed Rule

1. Air Quality in the Uinta Basin

The requirements in this proposed FIP are intended to address two concerns: 1) degraded air quality in the Uinta Basin due to ozone; and 2) regulatory requirements that are inconsistent between the Indian country lands within the U&O Reservation and State of Utah jurisdictions. VOC emissions, interacting with NO_X, chemically react in the atmosphere in the presence of sunlight to form ground-level ozone. Ozone levels in the Uinta Basin have exceeded the ozone NAAQS numerous times and represent a serious public health concern. The current NAAQS for ozone is 70 parts per billion (ppb[12]). Compliance with the NAAQS is determined by comparison to a "design value" calculated based on a three-year average of the fourth highest daily maximum 8-hour average ozone concentration measured in a year at each monitoring site. Based on the 2012 to 2014 regulatory air quality monitoring data, the 2014 ozone design values exceed the ozone NAAQS at three monitoring sites in the Uinta Basin. The current maximum regulatory three-year design value (2012-2014) is 77 ppb at the Roosevelt monitor. Based

[12] Information on the October 1, 2015 revised ozone standard is available at http://www3.epa.gov/airquality/ozonepollution/actions.html#current, accessed December 2, 2015.

on preliminary 2015 monitoring data, five monitoring sites in the Uinta Basin are estimated to exceed the ozone NAAQS[13]. Additionally, higher ozone concentrations were observed at some sites before they were designated as regulatory monitors. For example, 8-hour average ozone concentrations reached values as high as 141 ppb at the Ouray monitor in March 2013. This concentration corresponds to an Air Quality Index value of 211, which is characterized as "Very Unhealthy."

2. Sources of Ozone-Related Emissions in the Uinta Basin

We reviewed the distribution of VOC and NO_X emissions by source sector in the Uinta Basin in the 2011 National Emissions Inventory,[14] which showed that oil and natural gas production emissions were estimated to be the largest anthropogenic contributor of VOC emissions in the Basin, second only to biogenics (vegetation and soil). Oil and natural gas production emissions were estimated to be the second largest contributor of NO_X emissions in the Basin, second only to electric generation. According to an oil and natural gas industry emissions inventory study by the Western Regional Air Partnership (WRAP),[15] a significant portion of projected 2012 VOC (80 percent) and NO_X emissions

[13] Regulatory ozone data are available at http://www3.epa.gov/airtrends/values.html, accessed December 2, 2015.

[14] 2011 National Emissions Inventory, available at http://www3.epa.gov/ttn/chief/net/2011inventory.html, accessed December 4, 2015. Analysis of the data is described in detail in the technical support document. Both the analysis and the technical support document can be viewed in the docket for this rule (Docket ID No. EPA-R08-OAR-2015-0709).

[15] Western Regional Air Partnership (WRAP), O&G Emissions Workgroup: Phase III Inventory, Uinta Basin Reports, 2012 Mid-Term Projection Technical Memo, "DEVELOPMENT OF 2012 OIL AND GAS EMISSIONS PROJECTIONS FOR THE

(75 percent) attributed to the oil and natural gas industry in the Uinta Basin were projected to occur on the Indian country lands within the U&O Reservation. Approximately 98 percent of VOC and 68 percent of NO_X emissions released on Indian country lands within the U&O Reservation are from existing oil and natural gas production minor source operations[16], and 70 percent of the active producing oil and natural gas wells in the Uinta Basin are on Indian country lands within the U&O Reservation[17]. Therefore, based on the distribution of VOC and NO_X emissions by source sector in the Uinta Basin in the 2011 National Emissions Inventory, oil and natural gas production sources, the majority of which are minor sources, are believed to be the most significant anthropogenic contributors to NAAQS exceedances in the Uinta Basin in comparison to all other industrial source types. Additionally, as explained later in this document, we believe that ozone levels in the Uinta Basin are most significantly influenced by VOC emissions from the accumulation of minor oil and natural gas

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UINTA BASIN," March 25, 2009, available at http://www.wrapair2.org/PhaseIII.aspx, accessed November 30, 2015. Analysis of the data is described in detail in the technical support document. Both the analysis and the technical support document can be viewed in the docket for this rule (Docket ID No. EPA-R08-OAR-2015-0709).

[16] Existing source registrations were submitted to the EPA under the Federal Indian Country Minor NSR Program at 40 CFR 49.160. In developing this proposed rule, we conducted an analysis of the registration information, including production and emission data, from sources on the Uintah and Ouray Indian Reservation. Data analyzed is current as of the 1st quarter of calendar year 2015. Our analysis is discussed in the technical support document for this rule. Both the analysis and the technical support document can be found in the docket for this rule (Docket ID No. EPA-R08-OAR-2015-0709).

[17] Data from Drilling Info available by subscription at http://info.drillinginfo.com, accessed November 1, 2015. Analysis of the data is described in detail in the technical support document for this rule, which can be found in the docket.

production operations.

3. State and Federal Regulation of VOC from Oil and Natural Gas Production in the Uinta Basin

Rules currently applicable to facilities on Indian country lands within the U&O Reservation. The majority of VOC emissions at existing minor oil and natural gas production facilities on Indian country lands within the U&O Reservation are likely not subject to federal emission control requirements under the CAA. Some VOC emissions from newer oil and natural gas production facilities on the Indian country lands within the U&O Reservation may already be, or will be, regulated directly under NSPS OOOO or, if finalized, under the proposed NSPS OOOO revisions and proposed NSPS OOOOa. However, approximately 76 percent of the active producing wells on Indian country lands within the U&O Reservation began producing before August 23, 2011, the applicability date of NSPS OOOO.[18] Further, applicability of the VOC emission control requirements of NSPS OOOO for storage vessels is based on uncontrolled VOC emissions per storage vessel; therefore, even storage tanks at facilities associated with oil and natural gas production wells that began production after the effective date of NSPS OOOO may have low enough VOC emissions that owners and operators are not required to control VOC emissions from storage vessels. According to existing source registrations submitted to the EPA under the Federal Indian Country Minor NSR Rule for facilities on the Indian

[18] Data from Drilling Info, accessed November 1, 2015. See footnote 17.

country lands within the U&O Reservation, only 232 of 5,169 facilities are reported as operating VOC emissions control devices on their storage tanks.[19] Some VOC emissions which are also hazardous air pollutants (HAPs) from certain existing facilities may be regulated under the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Oil and Natural Gas Production Facilities at 40 CFR Part 63, subpart HH (NESHAP HH).[20] However, the NSPS only applies to new, modified and reconstructed facilities as of a certain date, and the NESHAP is not expected to require emission controls for lower-emitting glycol dehydrators on the rural and remote Indian country lands within the U&O Reservation because the urban-based applicability criteria that are specified in the NESHAP HH will not be satisfied. Similar to the preconstruction permitting requirements that apply to new minor oil and natural gas production facilities under UDEQ jurisdiction, federal preconstruction permitting requirements in the Federal Indian Country Minor NSR rule may apply to new minor oil and natural gas production facilities on Indian country lands within the U&O Reservation. The Federal Indian Country Minor NSR rule applies to new or modified minor (as defined at 40 CFR 49.152) oil and natural gas production sources that exceed the minor source emission thresholds

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[19] See footnote 16.

[20] National Emission Standards for Hazardous Air Pollutants: Oil and Natural Gas Production and Natural Gas Transmission and Storage, originally published at 64 FR 32609 (June 17, 1999), and revised on June 29, 2001 (66 FR 34548), January 3, 2007 (72 FR 26), and August 16, 2012 (77 FR 49490). Information on these rulemakings is available at: http://www3.epa.gov/airquality/oilandgas/actions.html and http://www3.epa.gov/ttn/atw/oilgas/oilgaspg.html, accessed October 14, 2015.

in the rule. Currently, however, under the Federal Indian Country Minor NSR rule, owners or operators of new and modified minor oil and natural gas sources are only required to register with the EPA and are not required to obtain permits with emission limitations and operational control requirements. New and modified minor oil and natural gas production sources will not be required to obtain a permit before construction until October 3, 2016.[21] Sources for which construction begins before that date, if never modified, will not require a minor NSR permit. As explained previously, the EPA has analyzed emissions data submitted by the owners and operators of existing oil and natural gas production sources under the registration requirements of the Federal Indian Country Minor NSR rule (herein referred to as the existing source registration data), which shows that remote and rural minor oil and natural gas production facilities are the most significant anthropogenic sources of VOC emissions on the Indian country lands within the U&O Reservation. As of the first quarter of 2015, 5,169 existing minor oil and natural gas production sources had registered under the Federal Indian Country Minor NSR Rule, which represents 98 percent of the VOC emissions from CAA regulated sources on the Indian country lands within the U&O Reservation. Furthermore, only approximately 14 percent of those facilities, at the high end, may be subject to VOC

[21] The EPA revised the original permitting compliance deadline of March 2, 2016 for true minor sources in the oil and natural gas sector to October 3, 2016. "Review of New Sources and Modifications in Indian Country: Extension of Permitting and Registration Deadlines for True Minor Sources Engaged in Oil and Natural Gas Production in Indian Country," 81 FR 9109 (Feb. 24, 2016).

emission control requirements under NSPS OOOO, and very few, if any, are likely to be subject to HAP emissions control requirements for glycol dehydrators under NESHAP HH. Thus, most owners and operators of existing oil and natural gas production facilities are not obligated to obtain a permit and may have no control obligations whatsoever.

Rules applicable to facilities under UDEQ jurisdiction. The present level of Federal regulation of existing oil and natural gas operations on the Indian country lands within the U&O Reservation is in contrast to UDEQ regulation of existing oil and natural gas production operations on non-Indian-country lands. As explained previously, 70 percent of the oil and natural gas wells in the Uinta Basin are on Indian country lands within the U&O Reservation. Seventy-six percent of those wells began production before August 23, 2011, the effective date of NSPS OOOO, and emissions sources associated with those wells are, therefore, not required to control VOC emissions from crude oil and condensate storage tanks. Additionally, many affected emissions sources associated with wells on Indian country lands within the U&O Reservation that began production on or after August 23, 2011, may also not be required to control VOC emissions, because they do not meet the emissions-based applicability criteria in NSPS OOOO. Furthermore, new and modified true minor oil and natural gas production facilities are not at this time required to obtain a preconstruction permit under the Federal Indian Country Minor NSR Rule that would impose emissions control requirements.

In contrast, in areas that are within the Uinta Basin, but not on Indian country lands within the U&O Reservation, owners and operators of new and modified minor oil and natural gas production operations are subject to the preconstruction permitting requirements in the State of Utah's federally enforceable rules for permitting of new and modified sources (Utah Permitting Rules)[22] whenever uncontrolled actual emissions are greater than the minor source preconstruction permitting thresholds of five tons per year (tpy) per pollutant regulated under the Federal Indian Country Minor NSR rule (NSR-regulated pollutant). Utah has had a minor new source review program (preconstruction permits) since November 1969. The 5 tpy threshold was implemented in 1997 to clarify which sources should be permitted. Before 1997 there was no size threshold, and any minor source could be required to obtain permit. Additionally, owners and operators of all oil and natural gas production facilities, regardless of emissions levels, are subject to Utah's rules for the oil and natural gas industry (Utah Oil and Gas Rules).[23] These regulations impose basic operational requirements for all existing pneumatic controllers (must be low or no bleed), existing flares (must be equipped with an automatic ignition device), and tanker truck loading and unloading (must be done using submerged filling),

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[22] Utah Administrative Code Chapter R307-401 (*Permits: New and Modified Sources*), available at http://www.rules.utah.gov/publicat/code/r307/r307.htm; *see* 40 C.F.R. part 52, subpart TT.

[23] Utah Administrative Code Chapter R307-500 Series (*Oil and Gas*), available at http://www.rules.utah.gov/publicat/code/r307/r307.htm, accessed October 14, 2015. These rules are state-only rules and the UDEQ has not submitted them to the EPA for approval in the Utah SIP.

regardless of facility-wide emissions, as well as general duty provisions to operate all process and control equipment in a manner consistent with good air pollution control practices. As a result of Utah's regulations and permitting programs, UDEQ has mechanisms available through which it can subject owners and operators of existing oil and natural gas production facilities in its jurisdiction to legally and practically enforceable control requirements that reduce VOC emissions, helping to protect air quality and to provide regulatory certainty to owners and operators of oil and natural gas production operations. No federal counterpart to these requirements applies to the more than 5,000 existing oil and natural gas facilities on the Indian country lands within the U&O Reservation in the same region.

4. Requirements of Proposed FIP

Our intent in developing the requirements of this proposed FIP is to address the two concerns of degraded air quality in the Uinta Basin and inconsistent regulatory requirements between Indian country lands within the U&O Reservation and State of Utah jurisdictions. This proposed FIP represents an important step toward reducing VOC emissions from existing oil and natural gas production operations on Indian country lands within the U&O Reservation. The majority of the substantive VOC emissions control requirements in this proposed Reservation-specific FIP are consistent with the regulatory approach that we have approved in the Utah SIP under the Utah Permitting Rules. This Reservation-specific FIP proposes to regulate VOC emissions from: pneumatic controllers; tank truck loading; fugitive emissions; working, standing, breathing, and flashing losses from crude oil, condensate, and produced water storage tanks; glycol dehydrator still vents; and pneumatic pumps.

In addition to protecting public health and the environment by improving air quality on the U&O Reservation and in the Uinta Basin generally, this rule will create consistent requirements across jurisdictional boundaries. Similar to the regulatory structure that exists for existing oil and natural gas production facilities on non-Indian-country lands within and adjacent to the U&O Reservation, this rule will establish unambiguous, legally and practically enforceable VOC emissions control and reduction, monitoring, recordkeeping, and reporting requirements for existing oil and natural gas production, treatment, and storage operations. This rule will also give the regulated community certainty that requirements will be consistent across jurisdictional boundaries.

This rule will not replace potential permitting requirements for existing oil and natural gas production facilities, but in many cases it will impose legally and practically enforceable requirements that may lower a facility's potential to emit (PTE) VOC to a level that will allow the owners and operators to construct modifications at existing minor oil and natural gas facilities without being required to obtain a federal preconstruction permit for VOC under the Federal Prevention of Significant Deterioration (PSD) Permit Program at 40 CFR 52.21 or the Federal Indian Country Minor NSR Permit Program at 40 CFR 49.151. In general, to comply with the CAA without triggering federal PSD or

Indian Country Minor NSR preconstruction permitting requirements, an owner or operator must calculate a facility's total VOC PTE from all new or modified pollution-emitting sources and verify that it is less than the thresholds in the PSD and Federal Indian Country Minor NSR Permit Programs. Therefore, if compliance with this rule's requirements results in facility-wide VOC PTE levels that are lower than the thresholds in the PSD or Federal Indian Country Minor NSR Permit Programs, the source will not trigger permitting requirements, and could avoid PSD and Federal Indian Country Minor NSR permitting altogether. We note, however, that while we believe that VOC is the pollutant most likely to be emitted in quantities sufficient to require permitting at modified oil and natural gas production facilities, a facility may not avoid the PSD and Federal Indian Country Minor NSR permitting requirements if its emissions of any *other* regulated NSR pollutant are high enough to trigger permitting requirements under the PSD or Federal Indian Country Minor NSR Permit Programs.

We are seeking comment on the proposed rule's approach of addressing ground level ozone concerns on Indian country lands within the U&O Reservation by establishing and relying on requirements that are consistent with those imposed on existing oil and natural gas production facilities on non-Indian-country lands under UDEQ jurisdiction. Included in the docket for this rule are copies of the UDEQ rules and other state and federal rules that we considered in this process, as well as a technical support document explaining the requirements of those rules and comparing them to the requirements in this proposed FIP.

III. Background

A. Uintah and Ouray Indian Reservation

The Ute Indian Tribe is a federally recognized Indian tribe organized under the Indian Reorganization Act of 1934,[24] with its Constitution and By-Laws adopted by the Tribe on December 19, 1936 and approved by the Secretary of the Interior on January 19, 1937.[25] The Uintah and Ouray Indian Reservation was formerly the Uintah Valley and Uncompahgre Reservations, which were established pursuant to Executive Orders dated October 3, 1861, as confirmed by the Act of May 5, 1864, 13 Stat. 63, and January 5, 1882, respectively. The Tribe's Constitution and By-Laws reorganized three Ute Tribes into one, and clarified that tribal jurisdiction within the U&O Reservation extends to the territory within the original Uintah and Uncompahgre Reservations, which was later enlarged through the Hill Creek Extension Act of 1948.[26] The U&O Reservation currently includes all Indian country lands within its exterior boundaries which are defined by the 1861 & 1882 Executive Orders, the Act of May 5, 1864, the Hill Creek Extension Act of 1948, and several subsequent court decisions.[27] Pursuant to CAA section 301(d)[28] we are authorized to treat eligible Indian tribes in the same manner as

[24] *See* 43 Stat. 984, 25 U.S.C. §476 (IRA).
[25] *See* 81 FR 5019 (January 29, 2016); Constitution and By-Laws of the Ute Indian Tribe.
[26] 62 Stat. 72.
[27] *See* footnote 5.
[28] *See* 42 U.S.C. § 7601(d).

states (TAS) for purposes of implementing CAA provisions over their entire reservations and over any other areas within their jurisdiction.[29] The Ute Indian Tribe has not applied for TAS for the purpose of administering a Tribal Implementation Plan (TIP) under the CAA. There is thus currently no EPA-approved plan implementing the functions and provisions of this FIP on Indian country lands within the U&O Reservation. The FIP the EPA is proposing provides such a plan and applies to all Indian country lands within the exterior boundaries of the Uintah and Ouray Indian Reservation.

B. Tribal Authority Rule

Section 301(d) of the Clean Air Act (CAA) authorizes the EPA to treat Indian tribes in the same manner as states and directs the EPA to promulgate regulations specifying those provisions of the CAA for which such treatment is appropriate.[30] It also authorizes the EPA, when the EPA determines that the treatment of Indian tribes as identical to states is inappropriate or administratively infeasible, to provide by regulation other means by which the EPA will directly administer the CAA.[31] Acting principally under that authority, on February 12, 1998, the EPA promulgated the Tribal Authority Rule (TAR).[32] In the TAR, we determined that it was appropriate to treat tribes in the

[29] *See* 63 FR 7254-57 (February 12, 1998) (explaining that CAA section 301(d) includes a delegation of authority from Congress to eligible Indian tribes to implement CAA programs over all air resources within the exterior boundaries of their Reservations).
[30] 42 U.S.C. § 7601(d)(1) and (2).
[31] 42 U.S.C. § 7601(d)(4).
[32] "Indian Tribes: Air Quality Planning and Management." 63 FR 7254 (Feb. 12, 1998); 40 CFR 49.1 – 49.11.

same manner as states for all CAA statutory and regulatory purposes except a list of specified CAA provisions and implementing regulations thereunder.[33] That list of excluded provisions includes specific plan submittal and implementation deadlines for NAAQS-related requirements, among them the CAA section 110(a)(2)(c) requirement to submit a program (including a permit program as required in parts C and D of the CAA) to regulate the modification and construction of any stationary source as necessary to assure that the NAAQS are achieved. Other provisions for which we determined that we would not treat tribes in the same manner as states include CAA section 110(a)(1) (SIP submittal) and CAA section 110(c)(1) (directing the EPA to promulgate a FIP "within 2 years" after we find that a state has failed to submit a required plan or has submitted an incomplete plan, or within 2 years after we disapprove all or a portion of a plan).

The TAR preamble clarified that by including CAA section 110(c)(1) on the list at 40 CFR 49.4, the "EPA is not relieved of its general obligation under the CAA to ensure the protection of air quality throughout the nation, including throughout Indian country."[34] The preamble confirmed that the "EPA will continue to be subject to the basic requirement to issue a FIP for affected tribal areas within some reasonable time."[35] In the TAR, we thus exercised our discretionary authority under CAA sections 301(a) and 301(d)(4) to establish a regulation providing that we would promulgate without

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[33] 40 CFR 49.4.
[34] 63 FR at 7265 (February 12, 1998).
[35] *Id.*

unreasonable delay such FIP provisions as are necessary or appropriate to protect air quality, if tribal efforts do not result in adoption and approval of tribal plans or programs.[36]

In 2006, acting under that authority, we proposed the regulation: "Review of New Sources and Modifications in Indian Country" (Indian Country NSR rule).[37] As a part of this regulation, the EPA proposed to protect air quality from minor sources in areas covered by the Indian Country NSR rule by establishing a FIP program to regulate the modification and construction of minor stationary sources consistent with the requirements of section 110(a)(2)(c) of the CAA; we call this part of the Indian Country NSR rule the Federal Indian Country Minor NSR rule. As described further in section III.C., the Federal Indian Country Minor NSR rule provides a mechanism for issuing preconstruction permits for the construction of new minor sources and certain modifications of major and minor sources in areas covered by the rule. In developing the rule, the EPA conducted extensive outreach and consultation, along with a 7-month public comment period that ended on March 20, 2007. The comments provided detailed information specific to Indian country and the final Federal Indian Country Minor NSR rule incorporated many of the suggestions we received. We promulgated final rules on July 1, 2011,[38] and the FIP became effective on August 30, 2011.

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[36] 40 CFR 49.11(a).

[37] "Review of New Sources and Modifications in Indian Country," 71 FR 48696 (Aug. 21, 2006).

[38] "Review of New Sources and Modifications in Indian Country," 76 FR 38748 (July 1,

C. Federal Indian Country Minor NSR rule

1. What is the Federal Indian Country Minor NSR rule?

The Federal Indian Country Minor NSR rule applies to existing, new and modified minor stationary sources and to minor modifications at existing major stationary sources in Indian country[39] where there is no EPA-approved program in place. Tribes can elect to develop and implement their own EPA-approved program under the TAR,[40] but are not required to do so.[41] In the absence of an EPA-authorized program, the EPA implements the program. Tribes can request administrative delegation of the federal program from the EPA and may be authorized by the EPA to implement agreed upon rules or provisions on behalf of the Agency.

Currently, any existing and new stationary source in the oil and natural gas sector that emits or has the potential to emit a regulated NSR pollutant in amounts equal to or greater than the minor NSR thresholds in the Federal Indian Country Minor NSR rule, but less than the amount that would qualify the source as a major source or a major

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2011).

[39] 40 CFR 49.153. Existing sources are only subject to the registration requirements unless they undergo modification.

[40] To be eligible to develop and implement an EPA-approved program, under the Tribal Authority Rule a tribe must meet four requirements: (1) be a federally-recognized tribe; (2) have a functioning government carrying out substantial duties and powers; (3) propose to carry out functions pertaining to air resources of the reservation or other areas within the tribe's jurisdiction; and (4) be reasonably expected to be capable of carrying out the program. *See* TAR (footnote 32).

[41] Tribes can also establish permit fees under a tribal permitting program pursuant to tribal law, as do most states.

modification for purposes of the PSD or nonattainment major NSR programs, must submit an existing source registration to the EPA containing information on, among other things, facility-wide actual emissions of NSR regulated pollutants, information on the methods used to calculate the emissions, and descriptions of the various emitting activities and equipment operated at the facility. Beginning October 3, 2016,[42] the owner/operator of any new source must apply for and obtain a minor NSR permit before beginning construction. Likewise, the owner/operator of any existing stationary source (minor or major) must apply for and obtain a minor NSR permit before beginning construction of a physical or operational change that will increase the allowable emissions of the stationary source by more than the specified threshold amounts, if the change does not otherwise trigger PSD or nonattainment major NSR permitting requirements.[43]

2. What are the minor NSR thresholds?

The "minor NSR thresholds" establish cutoff levels for each regulated NSR pollutant. If a source's PTE is lower than the thresholds,[44] then it is exempt from the Federal Indian Country Minor NSR rule for that pollutant. New or modified sources in

[42] See footnote 21.

[43] A source may, however, be subject to certain monitoring, recordkeeping, and reporting (MRR) requirements under the major NSR program, if the change has a reasonable possibility of resulting in a major modification. A source may be subject to both the Federal Indian Country Minor NSR rule and the reasonable possibility MRR requirements of the major NSR program(s).

[44] See 40 CFR 49.153 and Table 3.

reservation areas of Indian country, and in other areas of Indian country under tribal jurisdiction,[45] that have a PTE equal to or greater than the minor NSR thresholds, but less than the major NSR thresholds (which are generally 100 or 250 tpy) are "minor sources" of emissions and subject to the Federal Indian Country Minor NSR rule requirements.[46] The minor NSR thresholds for VOC emissions for sources in Indian country are 2 tpy in nonattainment areas and 5 tpy in attainment and unclassifiable areas. The U&O Reservation is currently designated unclassifiable for ozone.

D. What is a FIP?

Under section 302(y) of the CAA, the term "Federal implementation plan" means "a plan (or portion thereof) promulgated by the Administrator to fill all or a portion of a gap or otherwise correct all or a portion of an inadequacy in a SIP, and which includes enforceable emission limitations or other control measures, means or techniques (including economic incentives, such as marketable permits or auctions of emissions allowances), and provides for attainment of the relevant national ambient air quality standard.". As discussed previously in section III.B., CAA sections 301(a) and 301(d)(4) and 40 CFR 49.11(a) authorize the EPA to promulgate such FIPs as are necessary or appropriate to protect air quality if a Tribe does not submit or receive EPA approval of a TIP.

The Federal Indian Country Minor NSR rule is an example of a FIP. In that rule,

[45] See footnote 6.
[46] See 40 CFR 49.151 through 49.161.

we promulgated a program to protect air quality in areas of Indian country where there was no EPA-approved minor NSR permit program to regulate construction of new and modified minor sources and minor modifications of major sources. After making a finding that it was necessary or appropriate, the EPA promulgated that FIP to ensure that air resources in areas covered by the Federal Indian Country Minor NSR rule are protected by establishing a preconstruction permitting program to regulate emissions increases resulting from construction and modification activities that are not already regulated by the major NSR permitting programs.

This proposed Reservation-specific FIP, which will reduce VOC emissions related to the formation of ozone, is also needed to protect air quality on the U&O Reservation, because exceedances of the ozone NAAQS have been demonstrated at air quality monitors on and around the Reservation. Further, there are no currently approved TIPs that apply to existing oil and natural gas production sources on the U&O Reservation. Finally, the majority of these sources are not currently subject to federally required controls. In particular, approximately 5,000[47] existing minor oil and natural gas production facilities operating on Indian country lands within the U&O Reservation are believed to be operating without any federally required emissions controls, because, unless they undergo a modification, they are not and will not be subject to any federal emissions standard or to permitting under the Federal Indian Country Minor NSR rule

[47] According to information provided by the owners or operators in the existing source registrations under the Federal Indian Country Minor NSR Rule.

that would impose emissions control requirements. To address this need, we propose to find that it is necessary and appropriate to exercise our discretionary authority under sections 301(a) and 301(d)(4) of the CAA and 40 CFR 49.11(a) to promulgate a Reservation-specific FIP containing legally and practically enforceable requirements to control and reduce VOC emissions from existing oil and natural gas production and storage operations on Indian country lands within the U&O Reservation to protect air quality.

E. Oil and Natural Gas Sector

The oil and natural gas sector in the Uinta Basin includes the extraction and production of oil and natural gas, as well as the processing, transmission and distribution of natural gas. Specifically for oil, the sector in the Uinta Basin includes all operations from the well to the transfer to an oil transmission pipeline or other means of transportation to a petroleum refinery. For natural gas, in the Uinta Basin the sector includes all operations from the well to the final end user. The petroleum refinery is not considered part of the oil and natural gas sector. Thus, with respect to crude oil, the oil and natural gas sector ends where crude oil enters an oil transmission pipeline or other means of transportation to a petroleum refinery.

The oil and natural gas sector in the Uinta Basin can generally be separated into four segments: (1) oil and natural gas production; (2) natural gas processing; (3) natural gas transmission and storage; and (4) natural gas distribution. The proposed FIP for oil and natural gas production facilities on Indian country lands within the U&O Reservation focuses on existing sources in the first segment, oil and natural gas production, because the existing sources in that segment cumulatively contribute the largest portion of VOC emissions from the oil and natural gas sector on the U&O Reservation. The oil and natural gas production segment in the Uinta Basin includes wells and all related processes used in the extraction, production, recovery, lifting, stabilization, and separation or treatment of oil or natural gas (including condensate). Production components in the Uinta Basin may include wells and related casing head, tubing head, and "Christmas tree" piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices, pneumatic pumps and natural gas dehydrators. Production operations in the Uinta Basin also include the well drilling, completion, and workover processes, and include all the portable non-self-propelled apparatuses associated with those operations. Production sites in the Uinta Basin include not only the sites where the wells themselves are located, but also centralized gas and liquid gathering facilities where oil, condensate, produced water, and natural gas from several wells may be separated, stored, and treated. Production components in the Uinta Basin also include the smaller diameter, low-to-medium-pressure gathering pipelines and related components that collect and transport the oil, natural gas and other materials and wastes from the wells or well pads.

The natural gas production segment in the Uinta Basin ends where the natural gas enters a natural gas processing plant. Where there is no processing plant, the natural gas production segment ends at the point where the natural gas enters the transmission segment for long-line transport. The crude oil production segment in the Uinta Basin ends at the storage and load-out terminal, which is the point of custody transfer to an oil pipeline or for transport of the crude oil to a petroleum refinery via trucks or railcars.

IV. Development of the Rule

A. Basis for the Rule

In making the decision to develop this proposed rule, we first determined that existing oil and natural gas production operations on Indian country lands within the U&O Reservation are largely uncontrolled and are, based on our current understanding, cumulatively the primary contributor, compared to other stationary sources, to measured exceedances of the ozone NAAQS in the Uinta Basin during winter months. According to actual emissions data submitted to the EPA by owners and operators as part of the minor source registration requirement in the Federal Indian Country Minor NSR rule, existing oil and natural gas production sources emit the overwhelming majority of the ozone precursor emissions of VOC on the Indian country lands within the U&O Reservation, including many of the more reactive VOCs, such as benzene, toluene, and formaldehyde, that are also HAPs. In addition, existing oil and natural gas production sources emit the majority of the ozone precursor emissions of NO_x on the Indian country lands within the U&O Reservation. The UDEQ, academics and others initiated a multi-phased study (the Uinta Basin Winter Ozone Study) in 2012 to identify the emissions sources and the unique photochemical processes that cause elevated winter ozone concentrations within the Uinta Basin. Measurements and modeling were conducted in the winters of 2012, 2013, and 2014.[48] The studies found that ozone production in the area is sensitive to reductions in VOC emissions, but relatively insensitive to reductions in NO_X emissions.[49] Therefore, in developing this rule, we have concentrated on determining the most effective control requirements to reduce VOC emissions from existing minor oil and natural gas production facilities.

B. Uinta Basin Air Quality Solutions: Stakeholder Feedback and Responses

We developed this rule in coordination with the Ute Indian Tribe and the UDEQ. As part of this coordination we evaluated the oil and natural gas production activities and sources of VOC emissions that are impacting air resources on Indian country lands within the U&O Reservation, and the differences in VOC emission reduction requirements for existing facilities in Indian country within the U&O Reservation compared to facilities operating in UDEQ jurisdiction. We held a meeting with the Ute Indian Tribe on July 22, 2015, to discuss the high ozone levels observed over recent years in the Uinta Basin during winter inversions, and options to address emissions from oil and natural gas production operations on Indian country lands within the U&O Reservation. Options

[48] Utah DEQ: Uinta Basin: Ozone: Overview Web page with reports on Uinta Basin Ozone Studies 2011 to 2014 field studies: http://www.deq.utah.gov/locations/U/uintahbasin/ozone/overview.htm. Detailed discussion of the studies are found in the technical support document, which can be viewed in the docket for this rulemaking (Docket ID No. EPA-R08-OAR-2015-0709).
[49] *Id.*

discussed at the meeting included an EPA rulemaking to propose oil and natural gas controls, relying on voluntary oil and natural gas control measures, and relying on Tribal authorities to reduce emissions from the oil and natural gas sector. At the meeting, we also evaluated how the UDEQ was regulating new and existing oil and natural gas production operations in the Uinta Basin. In coordination with the Ute Indian Tribe and the UDEQ, we discussed the need for a consistent, basin-wide strategy to address ozone issues in the Uinta Basin, focusing on existing minor oil and natural gas production sources. Underlying our joint planning was the assumption that new and modified oil and natural gas production operations are expected to be widely regulated by various federal and (where applicable) state regulations for the source category, such as NSPS OOOO, the proposed NSPS OOOO revisions and proposed NSPS OOOOa, NESHAP HH, and major and minor NSR permitting requirements.

On September 3 and 9, 2015, and October 20, 2015, the EPA, the Ute Indian Tribe, and the UDEQ held separate Uinta Basin stakeholder meetings with: (1) oil and natural gas operators and representatives; (2) environmental groups; (3) Federal Land Managers; and (4) local County officials to discuss our intent to collaboratively address ozone issues in the Uinta Basin and to solicit input on potential solutions. We discussed the importance of taking proactive steps to protect air quality in the Uinta Basin, which might avoid a potential ozone nonattainment designation for the 2015 ozone standard for the Basin when the EPA makes its expected decision in 2017, or might lessen the severity of a future, potential nonattainment designation. Additionally, we discussed that given the current compromised air quality in the Uinta Basin, having enforceable restrictions in place to reduce emissions from existing sources will help permit applicants demonstrate that new proposed sources will not cause or contribute to exceedances of the NAAQS, thus allowing us to continue to permit new major, synthetic minor, and minor sources of emissions on the Indian country lands within the U&O Reservation.[50] At the industry stakeholder meeting several industry representatives stated that they are already facing a heavy regulatory burden under the EPA's current and proposed regulations for the oil and natural gas sector. Further, industry representatives stated that any strategy for addressing existing sources in the Uinta Basin beyond voluntary measures already being implemented by the operators should wait until the EPA makes a designation decision. Finally, industry stakeholders pointed to an effort by the EPA, the UDEQ, and the Ute Indian Tribe that calls for operators to submit comprehensive emissions and operating data on existing sources to the EPA by January 2016.[51] The industry stakeholders

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[50] Under the Federal Indian Country Minor NSR rule, new or modified true minor sources in Indian country covered by that rule must obtain minor source permits demonstrating that the source will not cause or contribute to a NAAQS violation in an attainment area, and will not cause or contribute to a PSD increment violation (40 CFR §48.155(a)(7)(ii)).

[51] The EPA, the Ute Indian Tribe, and the UDEQ collected emissions data from operators in the Uinta Basin to improve the performance of photochemical models for winter ozone in the Uinta Basin. The emissions data from the Uinta Basin operators were submitted to the EPA starting in January 2016, and will be compiled and analyzed by the end of the first quarter of calendar year 2016. That emissions data collection is being covered under the existing ICR that EPA developed to support the Federal Indian Country Minor NSR Rule (EPA ICR No. 1230.27, OMB Control No. 2060-0003, approval expires 4/30/2017), and is an independent action from this proposed FIP, with different objectives. The proposed FIP is being covered under a separate ICR.

requested that we not take any action on existing sources in the Uinta Basin without first analyzing those data. Environmental group stakeholders expressed strong support for EPA action in the Uinta Basin and stressed the importance of regulating existing sources. Some of the Federal Land Managers expressed their concern with NOx emissions and the impacts on regional haze and acidification in the context of our stated intent to focus on VOC emissions, but appreciated our intent to develop an enforceable solution to reduce emissions from existing sources, recognizing that there are several projects proposing the addition of thousands of new oil and natural gas wells in the Uinta Basin.

Industry representatives expressed concern that we are developing this rule ahead of our effort to gather additional oil and natural gas emissions information for the Uinta Basin. We developed the proposed rule based on emissions information that we began receiving in 2011. The information is from existing source registration data submitted by the operators on Indian country lands within the U&O Reservation under the Federal Indian Country Minor NSR rule. It represents a comprehensive set of data on existing source emissions for oil and natural gas production facilities on Indian country lands within the U&O Reservation. We believe that these data provide a robust basis for the proposed FIP, strongly supporting that oil and natural gas VOC emissions in the basin are significant on the Indian country lands within the U&O Reservation, and the VOC emission controls proposed in the FIP will reduce these emissions and result in air quality benefits. The Uinta Basin emissions inventory effort is an independent effort to improve air quality modeling performance in the broader Uinta Basin.[52] When the initial Uinta Basin-specific oil and natural gas emission gathering effort is complete, we will review the data set and compare it against the Indian country registration data to see if updates to our cost analysis and emission reduction estimates are warranted. However, we do not anticipate that new emissions data will result in any changes to the proposed VOC emission control requirements given our intent to achieve consistency with state requirements.

C. Developing the Proposed Control Requirements

Our primary objective in developing proposed requirements to control VOC emissions from existing oil and natural gas production facilities on the Indian country lands within the U&O Reservation is to address the degraded air quality in the Uinta Basin resulting from high levels of ozone. In developing appropriate proposed VOC emission control requirements that would adequately improve air quality, our secondary objective is to ensure that the proposed requirements provide for regulatory consistency across jurisdictional boundaries, where it makes sense for the specific circumstances in

[52] Ozone modeling in the Uinta Basin shows a low negative bias for methane and total VOC emissions for the oil/gas sector within the Uinta Basin by a factor of 4.8 and 1.8 respectively, using the 2011 NEI; therefore, when we model air quality in the basin with the current EPA National Emission Inventory emissions data, we are finding that we underestimate the observed VOC levels by approximately a factor of two. *See* Ahmadov, R., et al. (2015) *Understanding high wintertime ozone pollution events in an oil and natural gas producing region of the western U.S., Atmospheric Chemistry and Physics, 15, 411-429, 2015*. Available at www.atmos-chem-phys.net/15/411/2015/doi:10.5194/acp-15-411-2015, accessed January 5, 2016.

the Uinta Basin, but does not contradict EPA findings for existing federal oil and natural gas sector standards for new and modified sources that apply nationally. For some VOC emissions sources at affected oil and natural gas production facilities, we determined that it was necessary to propose requirements that exceed existing federal oil and natural gas sector standards for new and modified sources nation-wide, as the VOC reductions that would be achieved by the proposed requirements are necessary to lower ozone levels specifically in the Uinta Basin and are already requirements that are being implemented by the UDEQ at existing oil and natural gas production facilities in their jurisdiction.

To develop appropriate requirements for the control of emissions from the existing oil and natural gas production operations on Indian country lands within the U&O Reservation, we analyzed an oil and natural gas sector emissions inventory study completed for the Uinta Basin by the WRAP,[53] in conjunction with the emissions data submitted by the owners and operators of existing oil and natural gas production sources under the registration requirements of the Federal Indian Country Minor NSR rule. We used this combined set of information to determine the equipment and operations that generate the largest portion of VOC emissions from these facilities. Information from the inventories indicates that 80 percent of VOC emissions in the Uinta Basin occur on Indian country lands within the U&O Reservation. The same information indicates that

[53] Western Regional Air Partnership (WRAP), Oil and Gas Emissions Workgroup: Phase III 2006 Base Year Emission Inventory Project for the Intermountain West, Uinta Basin Report, March 25, 2009, available at: http://www.wrapair2.org/PhaseIII.aspx, accessed December 14, 2015.

the highest VOC emissions from existing oil and natural gas production facilities in the Uinta Basin are emitted from (in order of highest to lowest): (1) crude oil and condensate storage tanks; (2) glycol dehydration systems; (3) pneumatic controllers; and (4) pneumatic pumps. Therefore, reducing VOC emissions from these emissions sources is expected to result in reductions of ozone in the Uinta Basin. To address our secondary objective in developing the proposed requirements of ensuring regulatory consistency and establish a level playing field of requirements across state and Indian country lands, we evaluated existing federal oil and natural gas sector regulations and UDEQ regulations and minor NSR permitting requirements to help identify appropriate requirements for controlling VOC emissions from the four emission sources based on what is already being required of existing oil and natural gas production facilities in the Uinta Basin. As explained previously, it is not expected that many of the existing oil and natural gas production facilities on Indian country lands within the U&O Reservation are subject to requirements to control VOC emissions under existing federal oil and natural gas sector regulations, such as NSPS OOOO and NESHAP HH.

The Utah Oil and Gas Rules[54] provide requirements for pneumatic controllers, flares, tank truck loading and unloading of hydrocarbon liquid and produced water, and other equipment at all existing oil and natural gas production facilities. The requirements specify that: (1) all existing pneumatic controllers must be low or no bleed, in accordance

[54] See footnote 23.

with the standards for pneumatic controller affected facilities specified in NSPS OOOO; (2) all existing flares must be equipped with operational automatic ignition devices; (3) all tank trucks used for loading and unloading of hydrocarbon liquid and produced water must be loaded using bottom filling or a submerged fill pipe; and (4) all production operations and equipment, including air pollution control equipment, must be designed, operated and maintained to minimize emissions of VOC to the atmosphere, in a manner consistent with good air pollution control practices for minimizing emissions, and to achieve any emissions limits imposed by UDEQ regulations and permits.

In addition to the Utah Oil and Gas Rules, owners and operators of new and modified minor oil and natural gas production facilities in the Uinta Basin that are under UDEQ jurisdiction are subject to the preconstruction permitting requirements in the Utah Permitting Rules[55] if uncontrolled actual emissions are greater than the minor source preconstruction permitting thresholds of 5 tpy per NSR-regulated pollutant. The permits, called Approval Orders (site-specific) or General Approval Orders (GAOs), require installation, operation, and maintenance of the best available control technologies for minor sources. What constitutes best available control technologies changes over time as new technologies and practices are introduced and become readily available and economically feasible. As of the date of this proposal, UDEQ considers minor source Best Available Control Technology (BACT) for controlling VOC emissions from oil and

[55] See footnote 22.

natural gas production operations to include: 1) capture of the emissions from crude oil, condensate and produced water storage tanks (working, standing, breathing, and flashing losses), glycol dehydrator still vents, and pneumatic pumps; and 2) routing those emissions through a closed-vent system either to a process unit where the emissions are recycled, to an operational combustor with a minimum VOC control efficiency of 98.0 percent and operated with no visible emissions, or to be incorporated into a product (e.g., a sales gathering line). The UDEQ permits also require at least annual inspections of fugitive emission components using EPA Method 21[56] or an optical gas imaging instrument, and repair of all identified leaking components.

For purposes of providing consistent VOC emissions control requirements in the Uinta Basin, we view UDEQ rules for the Uinta Basin as the most relevant requirements with which to seek consistency. As a matter of regional comparison, we also reviewed other state oil and natural gas production-related regulations for areas that are similar to Utah in industry, meteorology, or air quality concerns. In reviewing these regulations, we considered whether the technologies are being commonly used and required at existing facilities in other states, so as to ensure that the proposed FIP requirements are legally and practically enforceable, as well as reasonably achievable. We specifically reviewed

[56] The docket for this rule (Docket ID No. EPA-R08-OAR-2015-0709) contains several examples of UDEQ site-specific minor source NSR permits (aka approval orders) for Crude Oil and Natural Gas Well Sites and/or Tank Batteries (DAQE-AN151010001-15, DAQE-AN149250001-14, and DAQE-AN143640003-15), as well as an approval for coverage under the GAO for a Crude Oil and Natural Gas Well Site and/or Tank Battery (DAQE-MN149250001-14).

state-only rules and guidance from the Wyoming Department of Environmental Quality (WDEQ)[57] that apply statewide to oil and natural gas production, and in particular those that apply in the Upper Green River Basin ozone nonattainment area and the requirements of the Colorado Department of Public Health and Environment (CDPHE)[58] that apply statewide to oil and natural gas production, and in particular those that apply in the Denver Metro and North Front Range ozone nonattainment area. Those two nonattainment areas have experienced ozone issues similar to those in the Uinta Basin that are attributable in part to oil and natural gas production activities, and have been addressed through state and local rules that apply to the same emission units this rule seeks to address.

We developed requirements in this proposed FIP that reflect, to the extent practicable, the most relevant aspects of the state rules and guidance we reviewed that apply to existing oil and natural gas production facilities. The proposed rule requirements are, for the most part, similar to Colorado and Wyoming's requirements for crude oil, condensate, and produced water storage tanks, glycol dehydrators, pneumatic pumps, closed-vent systems, enclosed combustors and utility flares, pneumatic controllers, tank truck loading and unloading, and fugitive emissions detection and repair. However, we

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[57] "Oil and Gas Production Facilities, Chapter 6, Section 2 Permitting Guidance," WDEQ (available at http://deq.wyoming.gov/aqd/new-source-review/resources/guidance-documents, accessed October 19, 2015); Wyoming Nonattainment Area Regulations, Chapter 8, Section 6; 020-020-008 Wyo. Code R. § 6 (2016).
[58] Statewide Controls for Oil and Gas Operations and Natural Gas-Fired Reciprocating Internal Combustion Engines, 5 Code Colo. Regs. § 1001-9 (2016).

are proposing levels of control that are necessary to protect air quality and to make requirements across the Uinta Basin consistent. Therefore, the requirements in the proposed rule most closely reflect UDEQ requirements for existing oil and natural gas production facilities in the Uinta Basin. We note that this proposed FIP uses a different mechanism from that used by the UDEQ for regulating existing oil and natural gas production facilities in the Uintah Basin within their jurisdiction. Specifically, the UDEQ implements a combination of sector-specific state-only rules and a SIP-approved preconstruction minor source NSR permitting program, while we are proposing to address the same emissions sources through this one rulemaking. We must follow the minimum criteria in 40 CFR Part 51, the CAA, and the TAR for approval of rules in either a SIP or a TIP,[59] which include adequate monitoring, recordkeeping and reporting requirements to ensure the requirements are federally enforceable and enforceable as a practical matter. Therefore, the monitoring, recordkeeping and reporting requirements in this proposed rule may contain slight differences in appearance when compared to the Utah Permitting Rules and the Utah Oil and Gas Rules. The technical support document for this proposal contains a detailed analysis comparing the proposed rule requirements to the relevant state requirements reviewed.

D. Area and Facilities Covered by the FIP

[59] EPA has used the planning requirements applicable to States as a guide in developing this FIP.

Depending on the piece of equipment or operation and its date of construction, this rule, if adopted, will apply to some or all equipment/operations owned or operated at existing (constructed or modified before the effective date of the final rule) oil and natural gas production facilities[60] producing oil and natural gas from the Uinta Basin and located on Indian country lands within the U&O Reservation. A more detailed description of the Reservation is provided in Section III.A. (Uintah and Ouray Indian Reservation).

This rulemaking addresses concerns that have been raised about the impact on air quality of VOC emissions from existing oil and natural gas production development on Indian country lands within the U&O Reservation. In the future, if other areas of Indian country experience air quality degradation, we may propose other reservation- or area-specific FIPs as necessary or appropriate using our authority as described in Section III.B.

E. Effect on Permitting of Facilities

This rule is not a permitting program. It therefore does not subject the affected facilities to or exempt them from any Federal CAA permitting requirements, including PSD preconstruction permitting requirements at 40 CFR Part 52, Federal Indian Country

[60] For the purposes of this proposed rule, an oil and natural gas production facility consists of any stationary source engaged in the extraction and production of oil and natural gas, as well as the processing, transmission and distribution of natural gas, including the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, and separation or treatment of oil and/or natural gas (including condensate).

Minor NSR preconstruction permitting requirements at 40 CFR Part 49, and the Title V Operating Permit Program at 40 CFR Part 71. However, affected facilities complying with the rule will be able to take into account any VOC emission reductions from any required controls under the FIP when calculating their PTE for determining applicability of the permitting requirements to the existing affected facility or any future modifications of the affected facility.

Some affected facilities' PTE emissions for VOC or any other regulated NSR and/or Title V pollutant may exceed the applicability thresholds for PSD, Federal Indian Country Minor NSR rule, or Title V permitting even after complying with this rule. In such cases, the owners or operators of these facilities will be required to apply for and obtain appropriate permits at such time as they modify their facilities.

F. Registration Requirements

This rule does not exempt existing oil and natural gas production facilities that are true minor sources located on Indian country lands within the U&O Reservation from the registration requirements of the Federal Indian Country Minor NSR rule. Nor does this rule impose any additional registration requirements, as all existing true minor oil and natural gas production facilities with actual emissions equal to or greater than the minimum thresholds identified in the Federal Indian Country Minor NSR Rule for one or more NSR-regulated pollutants were required to submit a registration to the EPA.

G. Air Quality Review

All counties in Utah that include Indian country lands within the U&O Reservation are currently designated as "unclassifiable" for ozone under the CAA.[61] A designation of unclassifiable for the 2008 ozone standards was made in 2012 because there was insufficient information at that time to support a designation of nonattainment or attainment. However, the available information, mostly from non-regulatory air quality monitoring stations showed ozone levels above the 2008 ozone standard.

Current air quality conditions in the region of the U&O Reservation and in east-central Utah are of concern, with measured ambient ozone concentrations exceeding the current NAAQS for ozone of 70 ppb.[62] Compliance with the NAAQS is determined by comparison to a "design value" calculated as the three-year average of the annual fourth-highest daily maximum 8-hour average concentration of ozone measured at each monitoring site. Based on the most recent air quality monitoring data,[63] the 2012-2014 ozone design values exceeded the 2015 ozone NAAQS at three monitoring sites in the Uinta Basin.[64] The Ute Indian Tribe and the UDEQ operate 13 monitoring sites in east-central Utah that measure ambient air quality in the Uinta Basin, but not all of these sites

[61] *See* 40 CFR 81.335.

[62] Revised Ozone NAAQS was signed by EPA Administrator Gina McCarthy on October 1, 2015, available at http://www.regulations.gov, Docket No. EPA-HQ-OAR-2008-0699.

[63] Supporting air quality information is discussed in the Technical Support Document for this rule, found in the rule docket (Docket ID No. EPA-R08-OAR-2015-0709).

[64] There are multiple monitoring sites in the Uinta Basin; only two have air quality data for 2012 – 2014 that meets EPA Federal Reference Methods.

have regulatory data for 2012-2014 that meet EPA's monitoring requirements in 40 CFR Part 58.[65]

The ozone exceedances have occurred during recent winters when shallow temperature inversions and widespread snow cover on the ground have been present.[66] As mentioned previously regarding the ozone precursor pollutants VOC and NO_X, oil and natural gas production sources are the largest anthropogenic source category contributor of VOC emissions (40 percent) in the Uinta Basin, second only to biogenics (vegetation and soils at 57 percent), and are the second largest anthropogenic source category contributor of NO_X emissions (37 percent), second only to electric generation (coal & oil at 43 percent). Biogenic sources are not likely to emit VOC emissions in impactful quantities during winter months with widespread snow cover. VOC and NO_X emissions from intensive oil and natural gas development in the Basin are trapped below the inversion layers during persistent cold air pool conditions, and snow cover causes stronger inversion conditions. Ozone photochemistry is UV light dependent. Moreover, normally low levels of UV light in the winter don't allow for significant formation of ozone, but if a snow layer is present on the ground, UV light is reflected back through the

[65] Until a station has three full years of data that meets EPA's monitoring requirements in 40 CFR Part 58, the data cannot be used for NAAQS comparison. We expect that more of these monitors will have three complete years of regulatory data in the future.
[66] Utah DEQ: Uinta Basin: Ozone: Overview Web page with reports on Uinta Basin Ozone Studies 2011 to 2014 field studies: http://www.deq.utah.gov/locations/U/uintahbasin/ozone/overview.htm, accessed October 14, 2015.

trapped air pollution and inversion layer, causing UV light to react with the pollutants multiple times to enhance the production of ozone. As previously discussed, the UBWOS field studies found that ozone production in the Uinta Basin is sensitive to reductions in VOC emissions and relatively insensitive to reductions in NO_X emissions. As a result of the conclusions of these studies, the EPA quantified the emissions impacts from the emissions control measures proposed in this Reservation-specific FIP and determined that the proposed action will result in large reductions of VOC emissions at over 41,000 tpy, accompanied by relatively small increases in NO_x emissions at only 352 tpy. The ozone levels measured by regulatory monitors during summer months, or in the absence of snow cover in the Uinta Basin, have not exceeded the NAAQS. However, because the photochemical modeling conducted to date indicates that ozone in the Uinta Basin is more responsive to VOC, we expect that the VOC reductions achieved by the proposed FIP will be beneficial for reducing ambient ozone levels and the severity of any exceedances of the 8-hour ozone NAAQS that may occur at any time of the year.

The proposed FIP will establish legally and practically enforceable requirements to reduce VOC emissions from existing oil and natural gas production facilities. The proposed FIP does not exempt these facilities from other applicable regulatory or permitting requirements. We believe that air quality in this region will benefit from the VOC reductions sought in this proposed rule. Supporting air quality information is discussed in the Technical Support Document for this rule.[67]

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[67] The Technical Support Document includes a more detailed explanation of the air

H. Evaluation/Quantification of Control Technologies/Approaches

We evaluated the impacts of changes in VOC and NO_x emissions from the proposed requirements to use enclosed combustors and flares to control of VOC emissions at oil and natural gas production facilities on Indian country lands within the U&O Reservation as part of the technical analysis for this proposed rule. The EPA reviewed data from the existing minor source registrations and determined that a proposed requirement to design and operate control devices to achieve at least 98.0 percent VOC efficiency on average (while also meeting at least a 95.0 percent VOC control efficiency at all times), and a proposed fugitive emissions monitoring program at existing oil and natural gas production facilities will result in a reduction of VOC emissions of 41,700 tpy. The EPA 2011 NEI estimated that total oil and natural gas production-related VOC emissions in the Uinta Basin in 2011 were 115,527 tpy. The WRAP Oil and Gas Emissions Workgroup Phase III Inventory projected 2012 oil and natural gas sector VOC emissions at 127,495 tpy. Thus, for the Uinta Basin as a whole, the proposed Reservation-specific FIP is estimated to result in an overall 36 percent reduction in oil and natural gas production segment VOC emissions relative to the 2011 NEI and an overall 33 percent reduction in total oil and natural gas sector VOC emissions relative to the 2012 projection by the WRAP. Within the Tribal airshed, where the

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quality impacts of the proposed rule. It can be found in the docket for this rule (Docket ID No. EPA-R08-OAR-2015-0709).

WRAP projected 2012 oil and natural gas sector VOC emissions of 102,319 tpy, the proposed FIP would result in a 41 percent reduction.

In addition to the reductions described previously, the EPA estimates that the proposed rule will result in a reduction of about 8,700 tpy of HAP and about 78,000 tpy of methane as co-benefits.

The use of combustors or flares to control VOC generates some emissions of NO_X as part of the combustion process, and the EPA estimated that there would be an insignificant increase of 352 tpy of NO_X[68] distributed over the Uinta Basin from the use of flares and combustors, compared to 20,804 tpy oil and natural gas production NO_X emissions and a basin-wide total of 55,745 tpy NO_X emissions relative to the 2011 NEI, and compared to 16,547 tpy total oil and natural gas sector NO_X emissions projected for 2012 by the WRAP. The EPA did not perform modeling to evaluate impacts on the 1-hour average NO2 NAAQS, because the estimate of 352 tpy total for all affected facilities under the proposed rule comes to approximately 0.12 tpy of NO_X per facility, which is substantially lower than the 10 tpy de minimis threshold for NO_X modeling in the Federal Indian Country Minor NSR Rule.[69]

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[68] The Technical Support Document includes a more detailed explanation of the air quality impacts of the proposed rule. It can be found in the docket for this rule (Docket ID No. EPA-R08-OAR-2015-0709).

[69] In the regulations for PSD permitting at 40 CFR 52.21, modeling is not required as part of the permitting process if the estimated increase in emissions is less than the minor source NSR emission threshold for a pollutant, which is 10 tpy for NO_X per 40 CFR 49.153. The Technical Support Document, accessible in the docket for this rulemaking

I. Benefits and Costs of the Proposed Rule

To estimate the total cost of the proposed rule, as well as the dollar-per-ton VOC control cost, the EPA relied on existing cost analyses done in support of the 2015 proposed NSPS OOOO revisions and proposed NSPS OOOOa,[70] 2015 Draft Control Technique Guidelines (CTG) for existing sources in nonattainment areas,[71] and the 2012 Colorado Regulation 7.[72] To estimate the number of facilities and equipment impacted by the proposed Reservation-specific FIP, the EPA relied on the existing minor source registrations submitted by operators under the Federal Indian Country Minor NSR rule. Depending on an operator's existing fleet of facilities, the site specific conditions, and existing control equipment, the annual cost impact on a given operator is expected to be highly variable. Additionally, many of the strategies and controls required by the proposed Reservation-specific FIP will benefit operators through the recovery and sale of gas that would otherwise be vented to the atmosphere. These savings are not included in the cost analysis, but will increase the cost effectiveness of the rule. The complete cost

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(Docket ID No. EPA-R08-OAR-2015-0709), contains additional discussion regarding CO emissions resulting from combustion in relation to the CO NAAQS.

[70] Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector, Docket ID No. EPA-HQ-OAR-2010-0505, accessible online at http://www.regulations.gov or http://www3.epa.gov/airquality/oilandgas/pdfs/og_prop_ria_081815.pdf

[71] Control Techniques Guidelines for the Oil and Natural Gas Industry (Draft): http://www3.epa.gov/airquality/oilandgas/pdfs/og_ctg_draft_081815.pdf

[72] Initial Economic Impact Analysis For Proposed revisions to Colorado Air Quality Control Commission Regulation Number 7: https://www.colorado.gov/pacific/sites/default/files/062_R7-Initial-EIA-request-11-21-13-26-pgs-062_1.pdf

analysis by the EPA to support this FIP is included in the Technical Support Document for this rule.[73]

According to the information submitted by operators in the existing minor source registrations, of the estimated 3,410 total existing facilities on Indian country lands within the U&O Reservation with facility-wide VOC emissions equal to or greater than 5 tpy, approximately 188 indicated existing tank controls (flares or combustors). Where tank controls were not indicated at existing facilities, the EPA presumed the facilities have no existing tank controls. Based on data submitted by operators in the existing minor source registrations, 1,759 facilities on Indian country lands within the U&O Reservation have facility-wide VOC emissions of less than 5 tpy (44 indicated existing tank controls where an auto-igniter will be required) and will only be subject to the requirements of this proposed FIP for low-bleed pneumatic controllers, submerged tank loading/unloading, and properly maintained equipment. A breakdown of the estimated number of facilities impacted by this proposed rulemaking and how they are affected is presented in Table 2.

TABLE 2. EXISTING FACILITIES AFFECTED BY PROPOSED RULE

Number of Facilities Affected	**Description of Requirement**
3,017	Add combustor & piping to combustor, LDAR, submerged tank loading/unloading, and properly maintained equipment

[73] The Technical Support Document, accessible in the docket for this rulemaking includes a more detailed explanation of benefits and costs (Docket ID No. EPA-R08-OAR-2015-0709).

188	Add auto-igniter to existing combustor, LDAR, submerged tank loading/unloading, and properly maintained equipment
205	LDAR, submerged tank loading/unloading, and properly maintained equipment
44	Add auto-igniter to existing combustor, submerged tank loading/unloading, and properly maintained equipment
1,715	Submerged tank loading/unloading, and properly maintained equipment
All existing high-bleed pneumatic controllers will be retrofit with low-bleed (cannot allocate to particular facilities)	
5,169	**TOTAL Facilities Affected by Rulemaking**

Using control cost estimates from the CTG and Colorado Regulation 7 Cost Analysis, the total annualized cost of implementing all of the controls outlined in the proposed FIP for these pieces of equipment is estimated to be $78.3 million in 2015 US dollars.

The total emissions reductions expected under the proposed control requirements for existing, affected facilities operating on Indian country lands within the U&O Reservation are estimated to be 41,700 tpy of VOCs. Of this number, we expect about 14,330 tpy of VOC reduction from adding controls to storage tanks, about 15,350 tpy of VOC reduction from controlling dehydrators, and about 5,540 tpy of VOC reduction from controlling pneumatic pumps; it is assumed that all emissions will be routed to a combustor that will continuously meet at least 95.0 percent VOC control efficiency, and that is also designed and operated to achieve at least 98.0 percent VOC efficiency on average. For the remainder of the emission reductions, approximately 1,370 tpy of VOC are reduced by implementing an LDAR program and about 5,120 tpy of VOC are reduced by retrofitting or replacing high-bleed pneumatic controllers with low-bleed.

Using the total annualized cost of $78.3 million, the cost of control is estimated to be $1,876 dollar per ton of VOC reduced.

We have not quantified the monetary benefits of the proposed rule. While we expect that the avoided VOC emissions will result in improvements in air quality and reduce health and welfare effects associated with exposure to ozone, we lack the necessary quantitative and analytical tools to accurately determine health benefits from the proposed VOC emission reductions on the U&O Reservation. The challenge with quantifying VOC health benefits is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. With the data available, we are not able to provide a credible health benefits estimate for this rule, due to the differences in the locations of oil and natural gas emission points relative to existing information, the weather-dependent nature of high wintertime ozone levels, and the highly localized nature of air quality responses associated with VOC reductions. [74] However, we are including a qualitative discussion of the benefits of the reductions in ozone levels.

The Regulatory Impact Analysis[75] for the recently revised ozone NAAQS

[74] The EPA discussed this position in detail when proposing the NSPS OOOO revisions and NSPS OOOOa, as well as when promulgating the final revised ozone NAAQS, concluding that the available VOC benefit-per-ton estimates are not appropriate to calculate monetized benefits of those rules, even as a bounding exercise. The dockets for both proposed rulemakings are available at http://www.regulations.gov, Docket ID No. EPA-HQ-OAR-2010-0505-4776 and Docket ID No. EPA-HQ-OAR-2008-0699-4458.
[75] "Regulatory Impact Analysis of the Final Revisions to the National Ambient Air

contains a detailed discussion of the current state of knowledge on the health benefits associated with reducing ambient levels of ozone air pollution. When we describe ozone health benefits, we generally group them in two categories: (1) reduced incidence of premature mortality from exposure to ozone; and (2) reduced incidence of morbidity from exposure to ozone. Reductions in premature mortality can occur either as a result of reductions in short term exposures to ozone, which can benefit people at all ages, or as a result of reductions in lifetime exposures to ozone (age 30 to 99). Reduced morbidity from reduced exposure can occur through reduced: (1) hospital admissions—respiratory (age > 65); (2) emergency department visits for asthma (all ages); (3) asthma exacerbation (age 6-18); (4) minor restricted-activity days (age 18–65); and (5) school absence days (age 5–17).

V. Summary of FIP Provisions

A. Applicability

The proposed rule will apply to any person who owns or operates an existing oil and natural gas production facility producing from the Uinta Basin and located on the Indian country lands within the U&O Reservation. For the purposes of this proposed rule, an existing facility is one constructed or modified before the effective date of the final rule. Specifically, this proposed rule will apply to affected facilities on Indian country

Quality Standards for Ground-Level Ozone," U.S. Environmental Protection Agency, EPA-452/R-15-007, September 2015, http://www3.epa.gov/ozonepollution/pdfs/20151001ria.pdf.

lands within the U&O Reservation within the Crude Petroleum and Natural Gas Extraction Industry, North American Industry Classification System (NAICS) Code 211111.

B. Compliance Schedule

We are proposing that compliance with the rule be required no later than 18 months after the effective date of the final rule. We determined it is important to allow a reasonable period of time for owners and operators of affected existing facilities to conduct any necessary retrofit projects, including, lead time needed to acquire control devices, for manufacturer testing to be compliant with the proposed requirements, and to secure the necessary trained personnel to install compliant devices. Owners and operators of affected new or modified emissions sources subject to NSPS emission control requirements that completed construction after the date of publication of the proposed rule and before the effective date of the final rule are generallyrequired to comply by the effective date of the final rule (typically 60 days after publication of the final rule in the Federal Register). Therefore, we could not reasonably select a compliance deadline for existing sources any sooner than 60 days after publication of this final rule in the Federal Register. Some federal standards have allowed phased-in compliance up to three years from the effective date for the final rule, as is the case with NSPS OOOO, in part in response to public comments regarding likely delays in the availability of the number of required control devices and the necessary trained personnel to install the required control devices. In the NSPS OOOO, the newer, higher emitting affected storage vessels (constructed after April 12, 2013), referred to as Group 2 storage vessels, were required to be in compliance by April 15, 2014. The earliest, lower emitting affected storage vessels under the NSPS OOOO (those constructed between August 23, 2011, and April 12, 2013), referred to as Group 1 storage vessels, were required to be in compliance by April 15, 2015. The EPA had estimated there would be 20,000 affected facilities constructed between August 23, 2011 and April 12, 2013, that would need emissions controls, plus an additional 1,100 per year after April 12, 2013, so we finalized a phased-in compliance schedule that ranged from within 12 months of the effective date for Group 2 storage vessels to within 44 months of the effective date for Group 1 storage vessels. [76] Now that the phase-in compliance period has concluded, any new or modified affected storage vessels under the NSPS OOOO that completed construction prior to the effective date of the final rule must be in compliance by the effective, which is typically 60 days after publication of the final rule in the federal register. We are proposing the 18-month compliance deadline as a middle ground between the typical compliance deadline

[76] The reasons for implementing a delayed compliance schedule was discussed in detail in the preamble for the September 23, 2013 updates to the 2012 VOC performance standards for storage tanks used in crude oil and natural gas production and transmission (NSPS OOOO), published at 78 FR 58416 (Sep. 23, 2013), . The discussion can be found on pages 78 FR 58420 and 58424-58426. The EPA ultimately finalized a maximum 44-month phase-in compliance approach that first required compliance by newer affected storage vessels, which would have higher emissions, while assuring that owners and operators of all affected storage vessels had time to acquire and schedule installation of required control devices.

in many NSPS of 60 days after publication of the final rule in the Federal Register and the maximum 44-month compliance deadline in the NSPS OOOO. We believe a quicker compliance schedule than what was provided under the NSPS OOOO is reasonable for several reasons. First, we anticipate there will be about 3,000 affected existing oil and natural gas production facilities that may require equipment retrofit and installation of VOC emission control equipment under the proposed rule, which is significantly less than the number of estimated Group 1 and Group 2 affected storage vessels under the NSPS OOOO. Providing 18 months to install retrofits seems a reasonable amount of time for efficient, cost-effective project planning that accounts for a level, sustained equipment and labor resource demand that can be supported by the vendor community. Secondly, in coordination with the UDEQ, we are aware of evidence, based on the experience and observations of UDEQ compliance staff, that the majority of existing oil and natural gas production facilities that have been required to install VOC emission control retrofits in State of Utah jurisdictions have completed the required retrofits within 9 months of the effective dates of their minor source approval orders, ahead of the 18-month deadline in UDEQ approval orders for operators to notify the UDEQ of the status of retrofit construction.[77] The proposed 18-month compliance schedule in this proposed

[77] Email correspondence with UDEQ staff regarding their experiences regulating existing oil and natural gas production facilities in State of Utah jurisdiction is included in the docket for this rulemaking (Docket ID No. EPA-R08-OAR-2015-0709). UDEQ compliance staff target each new approval order for inspection within 18 months of the date it is issued. They document the status of construction at the time of inspection and note whether the permitted source has provided a notification of construction status,

FIP will allow time for operators to conduct the necessary retrofits, while at the same time begin achieving VOC emissions reductions as soon as practicable, such that the reductions might have a timely beneficial impact not only on air quality and human health, but also on the severity of the classification of any potential non-attainment designation for the 2015 revised ozone NAAQS. We are also proposing to allow an owner or operator to submit a request to the EPA in writing for an extension of the compliance deadline, which must include a detailed explanation of the reason for the request. Any approval or denial of an extension request, including the length of any approved extension, will be based upon the merits of each case. Factors that the EPA will consider in deciding whether to grant an extension request under the proposed provision include the economic and technical feasibility of meeting the proposed FIP's control requirements in the timeframe prescribed in it. We are seeking comment on the proposed compliance schedule or alternative compliance schedules that may be more appropriate, including information that supports the proposed time period or a different time period, such as data on average times to acquire, install, and test or obtain manufacturer certification of compliant control devices.

C. Provisions for Delegation of Administration to the Tribe

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which is required within 18 months of the date the approval order is issued. UDEQ compliance staff have inspected hundreds of such existing oil and natural gas production sources without observing any compliance issues with the 18-month notification requirement. While UDEQ compliance staff do not compile this information into any readily available summary format, details about the status of construction are included in the inspection report for each source.

We are proposing in section 49.4170 (Provisions for Delegation of Administration to the Tribe) to establish the steps by which the Ute Indian Tribe may request delegation to assist us with the administration of this rule and the process by which the Regional Administrator of EPA Region 8 may delegate to the Ute Indian Tribe the authority to assist with such administration. As described in the regulatory provisions, any such delegation will be accomplished through a delegation of authority agreement between the Regional Administrator and the Tribe. This section would provide for administrative delegation of this federal rule and does not affect the eligibility criteria under CAA section 301(d) and 40 CFR 49.6 for TAS should the Ute Indian Tribe decide to seek such treatment for the purpose of administering their own EPA-approved TIP under Tribal law. Administrative delegation is a separate process from TAS under the TAR. Under the TAR, Indian tribes seek EPA approval of their eligibility to run CAA programs under their own laws. The Ute Indian Tribe will not need to seek TAS under the TAR for purposes of requesting to assist us with administration of this rule through a delegation of authority agreement. If delegation does occur, the rule would continue to operate under federal authority on Indian country lands within U&O Reservation, and the Ute Indian Tribe would assist us with administration of the rule to the extent specified in the agreement. We would at all times retain authority to enforce the requirements of the FIP.

D. General Provisions

We are proposing in section 49.4171 (General Provisions): (1) a requirement to design, operate, and maintain all equipment used for hydrocarbon liquid and gas collection, storage, processing, and handling operations covered under this rule, in a manner consistent with good air pollution control practices and that minimizes leakage of VOC emissions to the atmosphere; (2) definitions; (3) assurances that, in order to ensure compliance, we will maintain our authority to require testing, monitoring, recordkeeping, and reporting in addition to that already required by an applicable requirement in a permit to construct or permit to operate; and (4) assurance that nothing in the rule will preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a facility would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed.

E. VOC Emission Control Requirements

Our primary objective in developing requirements to control VOC emissions from existing oil and natural gas production facilities is to improve air quality in the Uinta Basin by reducing the formation of ground level ozone. Our secondary objective is to develop regulatory requirements that are consistent between Indian country and State of Utah jurisdictions to the extent compatible with our primary objective. Table 3 provides an overview of the VOC emission control requirements in the proposed FIP as they compare to current federal and UDEQ requirements for existing oil and natural gas production facilities. The discussion that follows details the proposed requirements and how they compare to existing federal and state requirements.

TABLE 3 – PROPOSED VOC EMISSIONS CONTROL REQUIREMENTS

Proposed Requirements (Section)	TPY Threshold	Control Efficiency (percent)	Covered by UDEQ Regulations / Permit Requirements	Covered by NSPS OOOO	Covered by Proposed NSPS OOOO Revisions and Proposed NSPS OOOOa	Covered by NESHAP HH
Storage Tank VOC Emission Control Requirements (49.4172)	Aggregate uncontrolled VOC emissions ≥4 tpy	See VOC emission control devices (49.4176), below	Same as proposed FIP - Utah Permitting Rules (BACT for site-specific & general approval orders)	Tanks with PTE ≥ 6 tpy per tank constructed after August 23, 2011	Tanks with PTE ≥ 6 tpy per tank constructed after final rule applicability date, as proposed	Tanks with potential for flash emissions and actual annual average hydrocarbon liquid throughput ≥79,500 liters/day
Dehydrators VOC Emission Control Requirements (49.4173)		See VOC emission control devices (49.4176), below	Same as proposed FIP - Utah Permitting Rules (BACT for site-specific & general approval orders)	No	No, as proposed	Yes, except units at non-urban area sources with actual annual average flowrate of natural gas < 85,000 standard m^3/day
Pneumatic Pumps VOC Emission Control Requirements (49.4174)		See VOC emission control devices (49.4176), below	Same as proposed FIP - Utah Permitting Rules (BACT for site-specific & general approval orders)	No, but would be covered by Proposed NSPS OOOOa, as proposed	If a control device already on site and constructed after final rule applicability date, as proposed	No
Covers and Closed Vent System VOC Emission Control	Aggregate uncontrolled VOC emissions from	100	Same as proposed FIP - Utah Permitting Rules	100 percent of storage tank emissions, if	100 percent of storage tank emissions, if constructed	If required to control glycol dehydrators and/or storage vessel HAP

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Requirements (49.4175)	storage tanks, dehydrators and pneumatic pumps ≥ 4 tpy		(BACT for site-specific & general approval orders)	constructed after August 23, 2011	after final rule applicability date, as proposed	emissions
VOC Emission Control Devices (49.4176)	Aggregate uncontrolled VOC emissions from storage tanks, dehydrators and pneumatic pumps ≥4 tpy	98.0 on average	Same as proposed FIP - Utah Permitting Rules (BACT for site-specific & general approval orders)	95.0 percent, for use tanks with PTE ≥ 6 tpy per tank if constructed after August 23, 2011	95.0 percent, for use tanks with PTE ≥ 6 tpy per tank, if constructed after final rule applicability date, as proposed	If required to control glycol dehydrator or storage vessel HAP emissions, must reduce HAP by 95.0 percent, or maintain < 20 ppmv or 1 tpy benzene
Fugitive Emissions VOC Emission Control Requirements (49.4177)	Facility emissions ≥ 5 tpy	NA – Annual Surveys	Same as proposed FIP - Utah Permitting Rules (BACT for site-specific & general approval orders)	No	For well sites and compressor stations if constructed after final rule applicability date, as proposed	Ensure closed-vent system operates with no detectable emissions if required to control glycol dehydrator or storage vessel HAP emissions
Tank Truck Loading VOC Emission Control Requirements (49.4178)	None – applies to all existing facilities	NA – Submerged filling	Same as proposed FIP - Utah Oil and Gas Rules	No	No, as proposed	No
Pneumatic Controllers VOC Emission Control Requirements (49.4179)		NA – Replace high bleed with low bleed	Same as proposed FIP - Utah Oil and Gas Rules	If constructed after October 15, 2013	If constructed after final rule applicability date, as proposed	No
Other combustion devices (49.4180)		NA - must have automatic	Same as proposed FIP - Utah Oil and Gas Rules	No	No, as proposed	No

		ignition device				

Storage Tanks, Glycol Dehydrators, and Pneumatic Pumps

We are proposing in sections 49.4172 (Storage Tank VOC Emission Control Requirements), 49.4173 (Dehydrators VOC Emission Control Requirements), and 49.4174 (Pneumatic Pumps VOC Emission Control Requirements) to require that affected facilities meet either: 1) at least 95.0 percent VOC control efficiency continuously, and be designed and operated to achieve at least 98.0 percent VOC efficiency on average for the VOC emissions from working, standing, breathing, and flashing losses from crude oil, condensate, and produced water storage tanks, glycol dehydrator process vents (glycol dehydrator regenerator or still vent and the vent from the dehydrator flash tank, if present), and pneumatic pumps, where the aggregate uncontrolled actual emissions are greater than or equal to 4 tpy; or 2) a requirement to maintain the aggregate emissions of all storage tanks, glycol dehydrators, and pneumatic pumps at a facility at an uncontrolled actual VOC emission rate of less than 4 tpy. The alternative 4 tpy uncontrolled actual VOC emission rate will allow control devices to be removed from the affected facility and relocated to other affected facilities with aggregate uncontrolled actual storage tank, glycol dehydrator, and pneumatic pump VOC emissions greater than or equal to 4 tpy. The 4 tpy threshold is consistent with the storage vessel VOC emissions reduction requirements in NSPS OOOO, which allows a sustained uncontrolled VOC emission rate of less than 4 tpy as an alternative emission limit to the 95.0 percent VOC control.[78] As we previously stated for that rulemaking, we believe this threshold reflects the decline in production that all oil and natural gas wells experience over time and allows control devices to be reused at other locations, which can help alleviate control device shortages. We also believe controlling emissions above that level will achieve meaningful VOC reduction. The 4 tpy uncontrolled VOC emissions threshold is also consistent with the threshold at or above which the UDEQ requires VOC emissions controls for aggregate storage tanks, glycol dehydrators, and pneumatic pumps emissions at oil and natural gas production facilities through their minor NSR permitting program[79]. We are proposing that owners or operators of affected facilities must

[78] The Federal Register notice for the "Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards; Proposed Rule," at 78 FR 22126, April 12, 2013, discusses the rationale for this proposed alternative storage vessels standard. The final rule was published at 78 FR 58416 (Sep. 23, 2013).

[79] The docket for this rule contains several examples of UDEQ site-specific minor source NSR permits (approval orders) for Crude Oil and Natural Gas Well Sites and/or Tank Batteries (DAQE-AN151010001-15, DAQE-AN149250001-14, and DAQE-AN143640003-15). UDEQ site-specific approval order requirements are based on BACT analyses for oil and natural gas production facilities concluding that combustion of VOC emissions from crude oil and condensate storage tanks, glycol dehydrators, and pneumatic pumps is economically and technically feasible when the aggregate uncontrolled VOC emissions from those emissions sources is equal to or greater than 4 tpy. The analyses rely in part on the EPA's analysis in the April 12, 2013 NSPS OOOO reconsideration, and the finding that emissions from those three emissions sources at a single facility can feasibly be routed to the same combustor. Though the 4 tpy threshold is not specifically stated in the approval orders, if a facility applying for a site-specific approval order has aggregate storage tank, glycol dehydrator, and pneumatic pump VOC emissions equal to or greater than 4 tpy, the order contains requirements to control those emissions.

demonstrate that the aggregate uncontrolled actual VOC emissions from crude oil, condensate, and produced water storage tanks, glycol dehydrator process vents, and pneumatic pumps has been maintained below 4 tpy using records of monthly determinations of actual VOC emission rates for the 12 consecutive months immediately preceding the demonstration. The uncontrolled VOC emissions must be calculated using a generally accepted model or calculation methodology. The proposal requires that the owner or operator re-evaluate the uncontrolled actual VOC emissions on a monthly basis. If the results of the monthly determination show that the uncontrolled actual VOC emission rate is greater than or equal to 4 tpy, the owner or operator will have 30 days to meet the control system requirements specified below.

The proposed requirements specify that the owner or operator must capture and route all subject emissions through a closed-vent system to an enclosed combustor or utility flare capable of reducing the mass content of VOCs in the emissions vented to it, on average, by 98.0 percent. We note that combustion devices can be designed to meet 98.0 percent control efficiencies, and can control, on average, emissions by 98.0 percent or more in practice when properly operated.[80] We also recognize that combustion devices

[80] The EPA has currently reviewed performance tests submitted for 19 different makes/models of combustor control devices and confirmed they meet the performance requirements in NSPS subpart OOOO and NESHAP subparts HH and HHH. All reported control efficiencies were above 99.9 percent at tested conditions. EPA notes that the control efficiency achieved in the field is likely to be lower than the control efficiency achieved at a bench test site under controlled conditions, but we believe that these units should have no problem meeting 95.0 percent control continuously and 98.0 percent control on average when designed and properly operated to meet 98.0 percent control. See Performance Testing Summary Table in Rule Record.

designed to meet 98.0 percent control efficiency may not continuously meet this efficiency in practice, due to factors such as the variability of field conditions and downtime. Therefore, the proposed requirements specify that devices must continuously meet at least 95.0 percent VOC control efficiency, and in addition, control devices must be designed and operated to achieve at least 98.0 percent VOC efficiency on average.

The owner or operator also has the option to design their production and storage operations to recover 100.0 percent of the emissions as product and inject it into a gathering pipeline system for sale or other beneficial purpose.

Although the requirements in the existing EPA oil and natural gas sector standards, including NSPS OOOO, NESHAP HH, and the proposed NSPS OOOO revisions and proposed NSPS OOOOa, may not be exactly equivalent to the requirements in this proposed FIP, we believe that any differences are minimal, and will not result in significant differences in emission reductions or environmental benefits. An example of a minimal difference would be that NSPS OOOO, the proposed NSPS OOOOa, and NESHAP HH require 95.0 percent VOC reduction while we are proposing in this FIP to require that control devices be designed and operated to achieve, on average, at least 98.0 percent VOC reduction, in addition to continuously meeting at least 95.0 percent VOC reduction. This requirement relates to the VOC control efficiency that must be demonstrated by the utility flare or enclosed combustion device. As explained later in more detail in the discussion on VOC emission control devices, we believe control devices designed and operated to achieve, on average, at least a 98.0 percent VOC reduction, in addition to continuously meeting at least a 95.0 percent VOC reduction are necessary for meaningfully reducing VOC emissions to reduce ambient ozone levels in the Uinta Basin and is achievable, and is consistent with the UDEQ requirements for existing oil and natural gas production facilities. During development of NSPS OOOO, a minimum of 95.0 percent control was determined to be the best system of emission reduction (BSER) and able to consistently be achieved by affected facilities (e.g., storage vessels, centrifugal compressors) nationwide, although the EPA is aware that combustors and utility flares may be capable of achieving control efficiencies greater than 95.0 percent.[81] In determining BSER, the EPA must be confident that the control efficiency can be achieved at all times by every affected facility to which it applies.

We are proposing that the control devices proposed to be required must be operated under specific conditions as specified in sections 49.4176 (VOC Emission Control Devices) and 49.4181 (Monitoring Requirements).

These proposed requirements for storage vessels, glycol dehydrators, and pneumatic pumps are consistent with those in the Utah Permitting Rules for similar existing oil and natural gas production facilities in UDEQ's jurisdiction, are necessary for reducing VOC emissions in the Uinta Basin, and will provide legally and practically enforceable control of VOC emissions and regulatory certainty across jurisdictional

[81] See footnote 80.

boundaries. We are seeking comment on these proposed requirements, including comments and information supporting alternative VOC emission control requirements that would provide protection of the air quality in the Uinta Basin and also provide regulatory certainty across jurisdictional boundaries.

Covers, Closed-Vent Systems, and VOC Emission Control Devices

We are proposing in section 49.4175 (Covers and Closed Vent System VOC Emission Control Requirements) to require the use of covers on all crude oil, condensate, and produced water storage tanks and the use of closed-vent systems with all equipment to capture and route VOC emissions to control devices. Proposed section 49.4175 also specifies construction and operational requirements for the covers and closed-vent systems. The construction and operational requirements for the covers and closed-vent systems are based on NSPS OOOO and the proposed NSPS OOOOa requirements and are intended to provide legal and practical enforceability. In addition, section 49.4176 (VOC Emission Control Devices) proposes to require specific legally and practically enforceable construction and operational requirements for enclosed combustors and utility flares.

We are proposing in section 49.4175 (Covers and Closed Vent System VOC Emission Control Requirements) to require that each owner or operator equip the openings on each subject crude oil, condensate, and produced water storage tank with a cover that ensures that working, standing, breathing, and flashing losses are efficiently routed through a closed-vent system to a vapor recovery system, an enclosed combustor or a utility flare. We are proposing that each cover and all openings on the cover (e.g., access hatches, sampling ports, and gauge wells) must form a continuous barrier over the entire surface area of the crude oil, condensate, or produced water in the storage tank. Each cover opening must be secured in a closed, sealed position (e.g., covered by a gasketed lid or cap) whenever material is in the tank on which the cover is installed, except when it is necessary to use an opening: (1) to add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit); (2) to inspect or sample the material in the unit; or (3) to inspect, maintain, repair, or replace equipment inside the unit. These requirements for the method of control are consistent with the requirements for storage tanks under NSPS OOOO and proposed NSPS OOOOa and will ensure that consistent requirements apply to any storage tanks subject to this rule that are not subject to NSPS OOOO or the proposed OOOOa (if finalized).

We are proposing to require that each owner or operator subject to the requirement to control VOC emissions from working, standing, breathing, and flashing losses from crude oil, condensate, and produced water storage tanks, glycol dehydrator still vents, and pneumatic pumps must use closed-vent systems to collect and route the emissions to the respective vapor recovery or VOC emission control devices. We are proposing that all vent lines, connections, fittings, valves, relief valves, and any other appurtenance employed to contain and collect emissions, and transport them to the vapor recovery or VOC control equipment, must be maintained and operated properly during any time the control equipment is operating and must be designed to operate with no detectable natural gas emissions. If a closed-vent system contains one or more bypass devices that could be used to divert all or a portion of the emissions from entering the vapor recovery or VOC control devices, we are proposing that the owner or operator must meet one of the following options for each bypass device: (1) at the inlet to the bypass device properly install, calibrate, maintain, and operate a flow indicator capable of taking periodic readings and sounding an alarm when the bypass device is open such that the emissions are being, or could be, diverted away from the control device and into the atmosphere; or (2) secure the bypass device valve in the non-diverting position using a car-seal or a lock-and-key type configuration. These proposed requirements for covers and closed-vent systems are consistent with the requirements for similar equipment under NSPS OOOO and the proposed NSPS OOOOa and will ensure that the requirements apply to any covers and closed-vent systems subject to this rule that are not subject to NSPS OOOO or the proposed NSPS OOOOa (if finalized).

We are proposing to require in section 49.4176 (VOC Emission Control Devices) that each owner or operator follow the manufacturer’s written operating instructions, procedures and maintenance schedule to ensure the use of good air pollution control practices for minimizing emissions from each enclosed combustor or utility flare. Each enclosed combustor must have the capacity to reduce the mass content of the VOC in the natural gas routed to it by, on average, at least 98.0 percent for the minimum and maximum natural gas volumetric flow rate and British Thermal Unit (BTU) content routed to it. We note that NSPS OOOO and the proposed NSPS OOOOa require owners and operators to demonstrate that enclosed combustors and utility flares achieve the required VOC reduction. Under NSPS OOOO and the proposed NSPS OOOOa, owners and operators can make the demonstration by using certain models of combustor that have been tested by the manufacturer in accordance with specific requirements in the rule, by using combustors that are designed and operated in accordance with applicable requirements in 40 CFR 60.18(b), or by conducting performance testing of the combustor on their own that satisfies the specific requirements in the rule. For the purposes of this rule, we are proposing to require that all utility flares and enclosed combustors installed per this rule are models that have been tested by the manufacturer in accordance with specific requirements in NSPS OOOO and the proposed NSPS OOOOa, are devices that are designed and operated in accordance with applicable requirements in 40 CFR 60.18(b), or are devices for which the owner or operator has conducted performance testing of the devices that satisfy the specific requirements in the rule. We recognize that the federal oil and natural gas emissions standards, such as NSPS OOOO, the proposed NSPS OOOOa, and NESHAP HH require control devices to meet 95 percent VOC control efficiency, while this proposed FIP requires control devices be designed and operated to achieve, on average, at least a 98.0 percent VOC reduction, in addition to continuously meeting at least a 95.0 percent VOC reduction. During development of NSPS OOOO, a minimum of 95.0 percent control was determined to be the BSER and able to consistently be achieved by affected facilities (e.g., storage vessels, centrifugal compressors) nationwide, although the EPA is aware that combustors and utility flares, in many applications, may be capable of achieving control efficiencies greater than 95.0 percent.[82] In determining BSER, the EPA must be confident that the control efficiency can be achieved at all times by every affected facility to which it applies. With regard to the current action, we believe that requirements that control devices must continuously meet at least 95.0 percent VOC control efficiency, and in addition, be designed and operated to achieve at least 98.0 percent VOC control efficiency on average, are necessary for reducing VOC emissions on the Indian country lands within the U&O Reservation to improve ambient ozone levels in the Uinta Basin. Additionally, 98.0 percent VOC control efficiency is equivalent to the VOC control efficiency required by the UDEQ for existing oil and natural gas production facilities. We also believe that continuously meeting at least 95.0 percent VOC control efficiency and designing and operating control devices to achieve at least 98.0 percent VOC efficiency on average are achievable using control devices that are compliant with this proposed FIP. The EPA is aware that contemporary combustion devices most commonly used to comply with NSPS

[82] See footnote 80.

OOOO and NESHAP HH are capable of demonstrating greater than 98.0 percent VOC control efficiency in a controlled performance testing environment under ideal conditions, based on widespread and readily available manufacturer test data.[83] When coupled with the proposed requirements to route all captured VOC emissions through a closed-vent system with no leaks to a utility flare or combustion device designed such that there is sufficient capacity to reduce the mass content of VOC in the captured emissions routed to it by at least 98.0 percent for the minimum and maximum natural gas volumetric flow rate and BTU content routed to the device, we are confident that control devices compliant with the proposed FIP will be able to demonstrate on average 98.0 percent VOC control efficiency.

We have determined that certain work practice and operational requirements are also necessary for the practical enforceability of the proposed VOC emission reduction requirements for utility flares or enclosed combustors. We are proposing that utility flares and enclosed combustors must be operated within specific parameters to ensure the effective control of VOC emissions. (This was discussed in great detail in the preamble and technical support documents to the proposed and final NSPS OOOO).[84] Specifically, we are proposing that each owner or operator must ensure that each enclosed combustor or utility flare is: (1) operated at all times that emissions are routed to it; (2) operated with

[83] See footnote 80.

[84] These documents can be found in the docket for the NSPS OOOO rulemaking, Docket ID No. EPA-HQ-OAR-2010-0505, available at http://www.regulations.gov.

a liquid knock-out system to collect any condensable vapors (to prevent liquids from going through the control device); (3) equipped with a flash-back flame arrestor; (4) equipped with a continuous burning pilot flame; (5) equipped with a malfunction alarm and remote notification system to detect if the pilot flame fails while emissions are being routed through the device; (6) equipped with a continuous recording device, such as a chart recorder, data logger or similar device, or connected to a Supervisory Control and Data Acquisition (SCADA) system, to monitor and document proper operation of the enclosed combustor or utility flare; (7) maintained in a leak-free condition; and (8) operated with no visible smoke emissions.

Some of these proposed requirements for VOC emission control devices are not entirely consistent with Utah Oil and Gas Rules and/or Utah Permitting Rules. For instance, the UDEQ requires permittees of minor oil and natural gas production facilities to show compliance with the 98.0 percent VOC control device control efficiency by operating the device according to the manufacturer's written instructions when gases/vapors are routed to it, while this FIP proposes to also require that the device be performance tested by the manufacturer or the owner or operator. An additional example is that the Utah Oil and Gas Rules and minor source permits only require that flares be equipped with automatic ignition devices, while this FIP proposes the requirement for the device to be equipped with a continuous burning pilot flame, an electronically controlled automatic ignition device with a malfunction alarm and remote notification system to detect if the pilot flame fails while emissions are being routed through the device, and a continuous recording device to monitor and document proper operation of the enclosed combustor or utility flare. Where these requirements differ from the Utah Oil and Gas Rules and/or Utah Permitting Rules, we determined they were necessary to demonstrate compliance with the proposed requirements. They are also consistent with the NSPS OOOO[85] and the proposed NSPS OOOOa requirements for control devices and would allow oil and natural gas production facilities that are subject to both this proposed FIP and the control requirements of the NSPS to demonstrate compliance with both rules. These proposed requirements for VOC emission control devices will provide legally and practically enforceable control of VOC emissions to protect air quality, and will promote regulatory certainty across jurisdictional boundaries. Section 49.4176 allows owners or operators of oil and natural gas production facilities, upon receiving written approval, to use control devices other than an enclosed combustor or utility flare, provided they are capable of achieving at least 95.0 percent VOC control efficiency <u>continuously</u>, and in addition, are <u>designed and operated</u> to achieve at least 98.0 percent VOC control efficiency on average. This provision will allow for owners or operators to take advantage of technological advances in VOC emission control for the oil and natural gas production industry and will provide us with valuable information on any new control technologies.

[85] There are some exceptions, for example, the NSPS OOOO (and proposed NSPS OOOOa) only allows for a continuous burning pilot flame, not an electronically controlled automatic ignition device.

We are seeking comment on the Covers, Closed-Vent Systems, and VOC Emission Control Devices provisions in this proposed FIP, including comments and information supporting more or less stringent requirements that would provide legal and practical enforceability of the proposed requirement to reduce VOC emissions from storage tanks, glycol dehydrators, and pneumatic pumps by, on average, 98.0 percent by weight.

Fugitive Emissions Control

We are proposing in section 49.4177 (Fugitive Emissions VOC Emission Control Requirements) to require that each owner or operator of an oil and natural gas production facility with facility-wide actual VOC emissions equal to or greater than 5 tpy conduct annual inspections of the facility to reduce emissions from fugitive emission components, which we are proposing to define in section 49.4171 to include, among other things, valves, connectors, open-ended lines, pressure relief devices, closed-vent systems, and thief hatches on tanks. Each owner or operator will be required to develop and implement a Reservation-wide fugitive emissions monitoring plan for all of its affected facilities on Indian country lands within the U&O Reservation that must include the following requirements: (1) conduct an initial monitoring of fugitive emissions components at each affected facility within 18 months of the effective date of the rule; (2) conduct subsequent monitoring at least once every 12 months after the initial monitoring; (3) increase monitoring frequency to once every 6 months if two or more leaks are detected during any single monitoring event, and allow reduction in frequency back to once every 12 months if no leaks are detected for 2 consecutive semi-annual monitoring events; (4) describe the fugitive emissions detection monitoring method to be used, which is limited to optical gas imaging instruments or EPA Method 21; (5) identification of manufacturer and model number of any leak detection equipment to be used; (6) procedures and timeframes for identifying and repairing components from which leaks are detected, including a requirement to repair any identified leaks from components that are safe to repair and that do not require facility shutdown within 15 days of identifying a leak; (7) identification of timeframes to repair leaks that are unsafe to repair[86] or require facility shutdown, but no later than the next required monitoring event; (8) procedures for verifying effective repair of leaking components; (9) specific training and experience needed to perform inspections; (10) description of procedures for calibration and maintenance of monitoring equipment to be used; and (11) standard monitoring protocol for a typical affected facility, including a general list of component types that will be inspected and what supporting data will be recorded (e.g., wind speed, detection method device-specific operational parameters, date, time, and duration of inspection). We are proposing in section 49.4177 of the proposed FIP to exempt facility owners and operators from having to monitor certain components for various reasons, such as: (1) the

[86] *Unsafe to repair* is defined in the proposed rule as meaning operator personnel would be exposed to an imminent or potential danger as a consequence of the monitoring or of the work to repair the leak.

monitoring could not occur without elevating the monitoring personnel or exposing the personnel to other immediate danger; or (2) the component to be inspected is buried, insulated, or otherwise obstructed in a manner that prevents access by a monitor probe or optical gas imaging device.

For new and modified oil and natural gas production facilities applying for coverage under the GAO or site-specific permits, we consider UDEQ's LDAR requirements to be as stringent as the LDAR requirements for well sites and compressor stations proposed under NSPS OOOOa, with the exception that the UDEQ requires inspection frequency changes based on production levels, while the proposed NSPS OOOOa requires inspection frequency changes based on the percentage of leaks identified. For existing oil and natural gas production facilities, we consider the UDEQ's LDAR requirements (annual only) to be less stringent than those proposed in NSPS OOOOa for well sites and compressor stations.

These proposed fugitive emissions LDAR requirements are consistent with those in the Utah Permitting Rules for similar oil and natural gas production facilities in UDEQ's jurisdiction, with one exception. The requirements in the proposed FIP are a hybrid of what UDEQ requires for existing facilities through the site-specific approval orders (annual LDAR inspections) and what is required for new facilities in Utah that apply for coverage under the GAO (potentially more frequent LDAR inspections than annual, depending on results of previous monitoring events). We believe that proposing this hybrid of UDEQ LDAR requirements is appropriate to reduce the number of newer facilities on Indian country lands within the U&O Reservation that will be subject to less stringent LDAR requirements than equivalent newer facilities in UDEQ's jurisdiction, because the effective date of this final rule will significantly overlap the date the UDEQ uses to distinguish between new and existing facilities[87]. Additionally, we are proposing inspection frequency changes based only on the number of leaks, and not on the crude oil and condensate throughput as required in Utah, because we believe the characteristics of the reservoir fluids produced and operating conditions in different areas of Indian country lands within the U&O Reservation are variable enough that a strict level of throughput may not equate to similar levels of VOC emissions from leaks from one facility to the next.

Since the fugitive emissions LDAR requirements for well sites and compressor stations in the proposed NSPS OOOOa are more stringent than the requirements in this proposed FIP, if owners or operators of affected oil and natural gas production facilities are subject to and in compliance with the requirements in the proposed NSPS OOOOa (if finalized), they will be considered to meet the proposed requirements in this FIP. The majority of the oil and natural gas production facilities we expect to be subject to this proposed FIP are not expected to be subject to the LDAR requirements in the proposed NSPS OOOOa, because the dates of construction pre-date the applicability criteria for the

[87] The UDAQ's GAO for a Crude Oil and Natural Gas Well Site and/or Tank Battery was effective June 5, 2014.

proposed NSPS OOOOa. Additionally, the proposed FIP requirements are intended to be consistent with UDEQ LDAR requirements for equivalent existing facilities operating in its jurisdiction. Therefore, if we were to propose LDAR requirements in this FIP as strict as those in the proposed NSPS OOOOa, the proposed FIP requirements would not meet our objective of regulatory consistency across jurisdictional boundaries. We are seeking comment on this proposed approach for LDAR requirements, as well as ideas for an alternative approach that provides consistency and regulatory certainty across jurisdictional boundaries.

<u>VOC Emission Control Requirements for All Existing Facilities</u>

Sections 49.4178, 49.4179, and 49.4180 contain proposed requirements for all existing oil and natural gas production facilities, regardless of facility-wide or emission unit specific emissions. Similar to the requirements in Utah's Oil and Gas Rules for existing oil and natural gas production facilities in UDEQ's jurisdiction: (1) tank trucks used for the transportation of intermediate crude oil, condensate, or produced water must be loaded using bottom filling or submerged pipe; (2) all existing pneumatic controllers must meet the pneumatic controller standards in NSPS OOOO at 40 CFR 60.5390(b)(2) and (c)(2), except for month and year of installation, reconstruction, or modification; and (3) all existing enclosed combustors, utility flares, or other open flares that are not required under Sections 49.4172, 49.4173, 49.4174, and 49.4176, must be equipped with an electronically controlled automatic ignition device. Neither the NSPS OOOO nor the

proposed NSPS OOOOa includes requirements for tank truck loading of crude oil, condensate, or produced water. As indicated by the proposed reference to the pneumatic controller standards in NSPS OOOO, the proposed FIP requirements for pneumatic controllers are mostly consistent with NSPS OOOO, with the exception of the month and year of installation, reconstruction, or modification, which is an exception also allowed by the Utah Oil and Gas Rules. The proposed requirement for all existing enclosed combustors, utility flares, or other open flares that are not required under Sections 49.4172, 49.4173, 49.4174, and 49.4176, to be equipped with an electronically controlled automatic ignition device is not consistent with NSPS OOOO or the proposed NSPS OOOOa, which require continuous burning pilot flames, but is consistent with the Utah Oil and Gas Rules, which require automatic igniters on all existing combustion devices. As discussed previously, Section 49.4176 VOC Emission Control Devices proposes to require continuous burning pilot flames to accommodate those existing oil and natural gas production facilities that would be subject to it and also subject to the NSPS requirements.

F. Monitoring Requirements

We are proposing in section 49.4181 (Monitoring Requirements) to require each owner or operator to conduct monitoring necessary for the practical enforceability of all of the proposed FIP's VOC emission reduction requirements, including: (1) monitoring of the number of barrels of crude oil, condensate, and produced water produced at the facility each time the oil is unloaded from the storage tanks; (2) directly measuring, or calculating using EPA-approved models, various parameters (e.g., product throughput, enclosed combustor flame presence, temperature) related to the proper operation of emissions units and required control devices to ensure compliance with the proposed FIP's emissions reduction requirements and operational limitations; and (3) visibility monitoring for detecting visible smoke from enclosed combustors and utility flares.

These proposed monitoring requirements are consistent with those in the Utah Permitting Rules for equivalent existing oil and natural gas production facilities in UDEQ's jurisdiction, and will ensure legally and practically enforceable control of VOC emissions and regulatory certainty across jurisdictional boundaries. These proposed monitoring requirements are also consistent with EPA oil and natural gas sector standards, including NSPS OOOO, the proposed NSPS OOOOa, and NESHAP HH, with some exceptions. The EPA standards do not require monitoring of the throughput of the storage tanks, but do require monitoring of the control device operating parameters that indicate proper operation, including visibility monitoring. We are seeking comment on the monitoring requirements in this proposed FIP, including comments and information supporting more or less stringent monitoring requirements that would provide legal and practical enforceability of the proposed VOC emission control requirements.

G. Recordkeeping Requirements

We are proposing in section 49.4182 (Recordkeeping Requirements) to require that each owner or operator of an affected oil and natural gas production facility keep specific records to be made available upon request, in lieu of voluminous reporting requirements. The records that must be kept include all required measurements, monitoring results, emissions calculations, and deviations or exceedances of rule requirements and corrective actions taken, as well as any manufacturer specifications and guarantees or engineering analyses. These recordkeeping requirements provide legal and practical enforceability for the control and emission reduction requirements of this rule.

H. Notification and Reporting Requirements

We are proposing in section 49.4183 (Reporting Requirements) to require that each owner or operator of an affected oil and natural gas production facility prepare and submit an annual compliance report, beginning 90 days after the end of the first compliance reporting period, which is one year after this rule becomes effective and covers the period for the previous calendar year. The report must include a summary of required records and a summary of deviations or exceedances of any requirements of the proposed FIP and the corrective measures taken. Additionally, a report must be submitted for any performance test we require. These reporting requirements provide legal and practical enforceability for the control and emission reduction requirements of this rule. We are seeking comments on the reporting frequency in this proposed FIP, including comments and information supporting a more or less frequent reporting schedule.

There is no need to propose to require owners or operators to register their oil and natural gas production facilities because the Federal Indian Country Minor NSR rule already requires registration of existing minor sources and such a requirement in this rule would be redundant. We are seeking comments on the decision not to require any notification or registration requirements in this proposed FIP, including comments and information supporting any need to require notification or registration.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This proposed action is not an economically significant regulatory action, but was determined to be an otherwise significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review under Executive Order 12866. Any changes made in response to the OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this proposed action, which is included in the technical support document for the proposed rule, available in the docket, and is summarized in *Section IV.I. Benefits and Costs of the Proposed Rule*. Because this proposed action is not economically significant, the EPA was not required to prepare a Regulatory Impact Analysis (RIA) of the potential costs and benefits associated with this proposed action.

B. Paperwork Reduction Act (PRA)

The information collection activities in this proposed rule have been submitted to the Office of Management and Budget (OMB) for approval under the PRA. The Information Collection Request (ICR) document that the EPA is preparing for this proposed FIP has been assigned EPA ICR number 2539.01.

This proposed action imposes a new information collection burden under the PRA. Once the ICR has been submitted to OMB, a notice advising people of that fact and of the opportunity for public comment will be published in the Federal Register.

The ICR covers information collection necessary to meet the requirements in the proposed FIP. In general, owners or operators are required to maintain records of all required monitoring and other rule compliance. The proposed FIP also requires annual reports containing information for each oil and natural gas production facility, including a summary of all required records during the reporting period, and a summary of all instances where operation was not performed in compliance with the requirements of the proposed FIP during the reporting period. Additionally, a summary emissions inventory is required for each facility covered under this rulemaking. These reports and records are essential in determining compliance, and are required of all sources subject to the proposed FIP. The information collected will be used by the EPA or the Ute Tribe to determine the compliance status of sources subject to the rule.

Respondents/affected entities: The potential respondents are owners or operators of existing oil and natural gas production facilities found throughout the Indian country lands within the U&O Reservation.

Respondent's obligation to respond: Mandatory. The EPA is charged under Sections 301(a) and 301(d)(4) of the CAA to promulgate regulations as necessary to protect tribal air resources. Promulgating the proposed FIP addresses an important initial step to fill a regulatory gap between state and federal requirements with regard to controlling VOC emissions from existing oil and natural gas production operations on the Indian country lands within the U&O Reservation. There is no other federal rule, including the recently finalized NSPS and NESHAP for the Oil and Natural Gas Sector (NSPS OOOO and NESHAP HH), that establishes air pollution control regulations for the particular oil and natural gas production operations that exist on the Indian country lands within the U&O Reservation. This is in contrast to oil and natural gas operations on non-Indian country lands within the State of Utah's jurisdiction, which are governed by the UDEQ regulations and Utah Division of Oil, Gas, and Mining regulations. Consistent with the regulatory structure that exists on non-Indian country lands, and NSPS OOOO, the proposed FIP has requirements for VOC emissions control and reductions, monitoring, recordkeeping, and reporting.

In addition, section 114(a) states that the Administrator may require any owner or operator subject to any requirement of this Act to:

- establish and maintain such records;
- make such reports; install, use, and maintain such monitoring equipment, and use such audit procedures, or methods;

- sample such emissions (in accordance with such procedures or methods, at such locations, at such intervals, during such periods, and in such manner as the Administrator shall prescribe);
- keep records on control equipment parameters, production variables or other indirect data when direct monitoring of emissions is impractical;
- submit compliance certifications in accordance with Section 114(a)(3); and
- provide such other information as the Administrator may reasonably require.

Estimated number of respondents: We estimate that 5,169 oil and natural gas production facilities will be subject to this proposed FIP over the next three years.

Frequency of response: Annual reports are required. Respondents must monitor all specified criteria at each affected facility and maintain these records for five years.

Total estimated burden: 170,801 hours per year (3-year average), for all operators subject to the proposed FIP.

Total estimated cost: $37,966,851 (per year includes $17,105,083 annualized capital or operation & maintenance costs), for all operators subject to the proposed FIP.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments to the EPA on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden, using the docket identified at the beginning of this proposed rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs via email to oria_submissions@omb.eop.gov, Attention: Desk Officer for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after receipt, OMB must receive comments no later than 30 days after publication of the ICR in the Federal Register. The EPA will respond to any ICR-related comments in the final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. For purposes of assessing the impacts of this rule on small entities, small entity is defined as: (1) a small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district, with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

The small entities subject to the requirements of this proposed action are oil and natural gas facilities on Indian country lands within the U&O Reservation. They were identified through review of existing minor source registrations submitted by owners and operators on the U&O Reservation under the Federal Indian Country Minor NSR rule. As of the first quarter of 2015, review of this minor source registration data identified 25 business entities (e.g., corporations, limited liability corporations, limited partnerships) who submitted registrations for oil and natural gas operations on the U&O Reservation. Each business and all of its affiliates were considered a single entity, in accordance with the SBA definition of "small business." Using the appropriate SBA threshold for the relevant NAICS codes, we found that 11 of the 25 businesses met the SBA definition of "small business." To conduct our screening analysis of regulatory impacts on small businesses, the compliance costs as a percentage of annual sales were determined for each small business. Next, to determine the thresholds for "significant economic impact" and a "substantial number" of companies, the EPA relied on commonly used criteria taken from the EPA's RFA guidance document.[88] Our screening analysis results indicate that one out of eleven, or nine percent, of the small businesses may incur a significant impact due to the rule. (The other ten small businesses are not expected to incur a significant impact.) Nine percent falls below the twenty percent criterion that is commonly used to determine what constitutes a substantial number of companies. Additionally, the one small business that may be significantly impacted owns only a single facility, which is currently under construction and not expected to begin oil

[88] The guidance, titled "EPA's Action Development Process: Final Guidance for EPA Rulewriters: Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (November 2006)" is available at http://www.epa.gov/reg-flex/epas-action-development-process-final-guidance-epa-rulewriters-regulatory-flexibility-act, accessed December 28, 2015.

production until the beginning of 2016. We expect that after oil production begins, sales for that business will increase, which will lead to a lower compliance cost as a percentage of annual sales for that business.

Therefore, based on this screening assessment, the EPA certifies that the rule is not expected to result in significant economic impacts for a substantial number of small companies. The complete small business analysis by the EPA to support this proposed FIP is included in the Technical Support Document, which can be found in the docket for this rulemaking.

D. Unfunded Mandates Reform Act (UMRA)

This proposed action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The proposed action imposes no enforceable duty on any state, local, or tribal government. This proposed action does impose certain duties on the private sector that will primarily affect existing oil and natural gas production facilities on Indian country lands within the U&O Reservation. However, its total estimated annual costs are $78,264,134, which is less than UMRA's $100 million dollar threshold (adjusted annually for inflation).

E. Executive Order 13132: Federalism

This proposed action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This proposed action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. The EPA has conducted outreach on this proposed rule consistent with its *EPA Policy on Consultation and Coordination with Indian Tribes* (May 4, 2011) via ongoing monthly meetings with tribal environmental professionals[89] before and during the development of this proposed action, via preliminary Tribal consultation with the Ute Indian Tribe Business Committee regarding options that the EPA could consider to address the Uinta Basin air quality concerns, and via ongoing stakeholder meetings where the Tribe was included and participated in emissions contributions discussions specific to the EPA's strategy for addressing the Uinta Basin air quality concerns. The EPA offered consultation on the proposed Reservation-specific FIP to elected Tribal officials of the Ute Indian Tribe and they requested a consultation, which was held on December 17, 2015. During the preliminary discussions on the proposed Reservation-specific FIP, the Tribe expressed concerns regarding their economic needs to develop and generate revenue from Tribal oil and natural gas resources, to consider air quality effects

[89] These monthly meetings are general in nature, dealing with many air-related topics, and are not specific to this proposed FIP.

on the health, safety and welfare concerns of their tribal membership living within the exterior boundaries of the U&O Reservation and the Uinta Basin, and to balance regulatory requirements for an even economic and regulatory playing field.[90] The Tribe requested two subsequent consultations, which were held via teleconference on January 14, 2016, and February 22, 2016, to further discuss the proposed Reservation-specific FIP and other unrelated topics. We addressed questions the Tribe had on the proposed FIP regarding the controls being considered, the ability for owners or operators to take credit for the controls for purposes such as permitting and NAAQS attainment, the estimated costs of proposed controls, the characterization of Indian country, and the breadth of oil and natural gas source category types proposed to be regulated.

Enacting a Reservation-specific FIP for the U&O Reservation is directly responsive to the Ute Indian Tribe's air quality concerns in that we are proposing to implement our CAA authority to protect air quality on and surrounding Indian country lands within the U&O Reservation in a manner that creates a level playing field with respect to requirements on adjacent state land. We will continue to provide outreach to tribal environmental professionals and continue consultation with tribal leadership on this proposed action.

G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

[90] The records of communication for all consultations and preliminary discussions with the Ute Indian Tribe are included in the docket for this rulemaking (Docket ID No. EPA-R08-OAR-2015-0709).

This action is not subject to Executive Order 13045 because it is not economically significant as defined in EO 12866, and because the EPA does not believe the environmental health or safety risks addressed by this proposed action present a disproportionate risk to children. In fact, this proposed Reservation-specific FIP should have a positive effect on the health of the residents of the U&O Reservation, including children, as it is expected to result in a reduction in ambient ozone concentrations, which disproportionately impact children, elderly, and those with respiratory ailments.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113[91] directs the EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical.

VCS are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. NTTAA directs the EPA to provide Congress, through OMB, explanations when the

[91] *See* 15 U.S.C. 272.

Agency decides not to use available and applicable VCS. The proposed rule involves references to technical standards. Therefore, the EPA conducted searches for the Oil and Natural Gas Sector: Emission Standards for New and Modified Sources through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). Searches were conducted for EPA Methods 21 and 22 of 40 CFR part 60 Appendix A-7 and part 63 Appendix A.[92] No applicable VCS were identified for EPA Methods 21 and 22[93]. The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this proposed regulation.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this proposed action does not have the potential to cause

[92] The EPA Reference Methods 21 and 22 can be accessed online at http://www.ecfr.gov/cgi-bin/text-idx?SID=3460cbde2fb95fe7c3727e775acc41b3&mc=true&node=pt40.8.60&rgn=div5 (Part 60), and http://www.ecfr.gov/cgi-bin/text-idx?SID=3460cbde2fb95fe7c3727e775acc41b3&mc=true&node=ap40.15.63_112006_663_112099.a&rgn=div9 (Part 63), both accessed December 23. 2015.

[93] "Voluntary Consensus Standard Results for Approval and Promulgation of Federal Implementation Plan for Existing Oil and Natural Gas Well Production Facilities; Uintah and Ouray Indian Reservation in Utah," Memorandum from Steffan Johnson, Group Leader, U.S. EPA, Measurement Technology Group, to Deirdre Rothery, Unit Chief Air Permitting and Monitoring Unit, U.S. EPA Region 8 Air Program, dated November 12, 2015, available in the Docket for this proposed rule (Docket ID No. EPA-R08-OAR-2015-0709).

disproportionately high and adverse human health or environmental effects on minority, low-income, or indigenous populations. Our primary goal in developing this proposed rule is to protect the communities in and near Indian country lands within the U&O Reservation, where existing oil and natural gas production operations have been shown to contribute to exceedances of the ozone NAAQS. The impacts of this proposed rule are expected to be beneficial, rather than adverse, and its benefits are expected to accrue to communities in and near Indian country lands within the U & O Reservation. As explained previously in the "Air Quality Review" section, the EPA has quantified the expected emissions impacts from this proposed action, and found that the proposed action will result in large reductions of VOC emissions. We do expect that there will be small increases in NOx emissions, but we do not expect these increases to cause adverse health or environmental impacts.

This proposed action will also provide regulatory certainty to owners and operators, by imposing, to the extent appropriate, requirements that are consistent with those applicable to such existing sources that are regulated by the UDEQ because they are not on Indian country lands within the Reservation. This will ensure that air quality is protected consistently on state and tribal lands and avoid disproportionate impacts.

Further discussion of the EPA's environmental justice analysis appears in the Technical Support Document for this rule.

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List of Subjects in 40 CFR Part 49

Environmental protection, Administrative practice and procedure, Air pollution control, Indians, Indians-law, Indians-tribal government, Intergovernmental relations, reporting and recordkeeping requirements.

Dated: April 1, 2016

Shaun L. McGrath,
Regional Administrator,
Region 8

For reasons set forth in the preamble, part 49 of title 40 of the Code of Federal Regulations proposes to amend as follows:

PART 49--[AMENDED]

1. The authority citation for part 49 continues to read as follows:

Authority: 42 U.S.C. 7401, et seq.

Part 49 - INDIAN COUNTRY: AIR QUALITY PLANNING AND MANAGEMENT

Subpart K – Implementation Plans for Tribes – Region VIII

2. Add §§ 49.4169 through 49.4183 under the undesignated center heading "Federal Implementation Plan for Existing Oil and Natural Gas Production Facilities; Uintah and Ouray Indian Reservation in Utah," to read as follows:

Federal Implementation Plan for Existing Oil and Natural Gas Production Facilities; Uintah and Ouray Indian Reservation in Utah

49.4169 Introduction.

49.4170 Delegation of authority of administration to the tribe.

49.4171 General provisions.

49.4172 Storage Tank VOC Emission Control Requirements.

49.4173 Dehydrators VOC Emission Control Requirements.

49.4174 Pneumatic Pumps VOC Emission Control Requirements.

49.4175 Covers and Closed Vent System VOC Emission Control Requirements.

§ 49.4169 Introduction.

(a) *What is the purpose of §§ 49.4169 through 49.4183?* Sections 49.4169 through 49.4183 establish legally and practically enforceable requirements to control and reduce VOC emissions from well production and storage operations, and gathering and boosting operations at existing oil and natural gas production facilities (as defined in §49.4171(b)(14)) on Indian country lands within the Uintah and Ouray Indian Reservation in Utah (the "Uintah and Ouray Indian Reservation").

(b) *Am I subject to §§ 49.4169 through 49.4183?* Sections 49.4169 through 49.4183, as appropriate, apply to each owner or operator of an existing oil and natural gas production facility that meets certain applicability thresholds (as defined under each section), and that is located on Indian country lands within the Uintah and Ouray Indian Reservation. For the purposes of this rule an existing oil and natural gas production facility is a facility that commenced construction before [**INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER**]. However, not all equipment at all existing facilities is subject to regulation under this Reservation-specific FIP. Generally, those pieces of equipment at facilities that are existing as of [**INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER**] that are already subject to and in compliance with VOC emission control requirements under another EPA standard, as specified in each appropriate subsection below, are considered to be in compliance with the requirements to control VOC emissions from that same equipment under this FIP.

(c) *When must I comply with §§ 49.4169 through 49.4183?* Compliance with §§ 49.4169 through 49.4183 is required no later than [**INSERT DATE 18 MONTHS AFTER EFFECTIVE DATE OF THE FINAL RULE**]. You may submit a written request to the EPA for an extension of the compliance date which sets for the specific reasons for the requested extension. Any decision to approve or deny the request, including the length of time of an approved request, will be based on the determined merits of case-specific circumstances.

§ 49.4170 Delegation of authority of administration to the tribe.

(a) *What is the purpose of this section?* The purpose of this section is to establish the process by which the Regional Administrator may delegate to the Ute Indian Tribe the authority to assist the EPA with administration of this FIP. This section provides for administrative delegation and does not affect the eligibility criteria under 40 CFR 49.6 for treatment in the same manner as a state.

(b) *How does the Ute Indian Tribe request delegation?* In order to be delegated authority to assist us with administration of this FIP, the authorized representative of the Ute Indian Tribe must submit a written request to the Regional Administrator that:

(1) Identifies the specific provisions for which delegation is requested;

(2) Includes a statement by the Ute Indian Tribe's legal counsel (or equivalent official) that includes the following information:

(i) A statement that the Ute Indian Tribe is an Indian tribe recognized by the Secretary of the Interior;

(ii) A descriptive statement that meets the requirements of § 49.7(a)(2) and demonstrates that the Ute Indian Tribe is currently carrying out substantial governmental duties and powers over a defined area;

(iii) A description of the laws of the Ute Indian Tribe that provide adequate authority to carry out the aspects of the rule for which delegation is requested; and

(3) Demonstrates that the Ute Indian Tribe has, or will have, adequate resources to carry out the aspects of the rule for which delegation is requested.

(c) *How is the delegation of administration accomplished?* (1) A Delegation of Authority Agreement setting forth the terms and conditions of the delegation and specifying the provisions of this rule that the Ute Indian Tribe will be authorized to implement on behalf of the EPA will be entered into by the Regional Administrator and the Ute Indian Tribe. The Agreement will become effective upon the date that both the Regional Administrator and the authorized representative of the Ute Indian Tribe have signed the Agreement. Once the delegation becomes effective, the Ute Indian Tribe will be responsible, to the extent specified in the Agreement, for assisting us with administration of the FIP and will act as the Regional Administrator as that term is used in these regulations. Any Delegation of Authority Agreement will clarify the circumstances in which the term "Regional Administrator" found throughout the FIP is to remain the EPA Regional Administrator and when it is intended to refer to the "Ute Indian Tribe," instead.

(2) A Delegation of Authority Agreement may be modified, amended, or revoked, in part or in whole, by the Regional Administrator after consultation with the Ute Indian Tribe.

(d) *How will any Delegation of Authority Agreement be publicized?* The Agency will publish a notice in the Federal Register informing the public of any Delegation of Authority Agreement with the Ute Indian Tribe to assist us with administration of all or a portion of the FIP and identifying such delegation in the FIP. The Agency will also publish an announcement of the delegation of authority agreement in local newspapers.

§ 49.4171 General provisions.

(a) At all times, including periods of startup, shutdown, and malfunction, each owner or operator must, to the extent practicable, design, operate, and maintain all equipment used for hydrocarbon liquid and gas collection, storage, processing, and handling operations covered under §§ 49.4169 through 49.4183, regardless of size and including associated air pollution control equipment, in a manner that is consistent with good air pollution control practices and that minimizes leakage of VOC emissions to the atmosphere.

(b) *Definitions*. As used in §§ 49.4169 through 49.4183, all terms not defined herein have the meaning given them in the Act, in 40 CFR Part 60, subparts A, OOOO, and OOOOa, in 40 CFR Part 63, subparts A and HH, in the Prevention of Significant Deterioration regulations at 40 CFR 52.21, or in the Federal Minor New Source Review Program in Indian Country at 40 CFR 49.151. The following terms have the specific meanings given them:

(1) *Closed vent system* means a system that is not open to the atmosphere and that is composed of hard-piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gaseous vapors from a piece or pieces of equipment to a control device or back to a process.

(2) *Condensate* means hydrocarbon liquid separated from produced natural gas that condenses due to changes in temperature, pressure, or both, and that remains liquid at standard conditions.

(3) *Crude oil* means hydrocarbon liquids that are separated from well-extracted reservoir fluids during oil and natural gas production operations, and that are stored or injected to pipelines as a saleable product. Condensate is not considered crude oil.

(4) *Electronically controlled automatic ignition device* means an electronic device which generates sparks across an electrode and reaches into a combustible gas stream traveling up a flare stack or entering an enclosed combustor, at the point of the pilot tip, equipped with a temperature monitor that signals the device to attempt to re-light an extinguished pilot flame.

(5) *Enclosed combustor* means a thermal oxidation system with an enclosed combustion chamber that maintains a limited constant temperature by controlling fuel and combustion air.

(6) *Existing facility* means an oil and natural gas production facility that commenced construction before [**INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER**].

(7) *Flare* means a thermal oxidation system using an open (without enclosure) flame.

(8) *Flashing losses* means natural gas emissions resulting from the presence of dissolved natural gas in the crude oil, condensate, or produced water, which are under high pressure that occurs as the liquids are transferred to storage tanks that are at atmospheric pressure.

(9) *Fugitive emissions component* means any component that has the potential to emit fugitive emissions of VOC at an oil and natural gas production facility, such as valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed-vent systems, thief hatches or other openings on storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors,

separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.

(10) *Glycol dehydration unit* means a device in which a liquid glycol (including ethylene glycol, diethylene glycol, and triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.

(11) *Glycol dehydration unit process vent emissions* means VOC-containing emissions from the glycol dehydration unit regenerator or still vent and the vent from the dehydration unit flash tank (if present).

(12) *Malfunction alarm and remote notification system* means a system connected to an electronically controlled automatic ignition device that sends an alarm through a remote notification system to an owner or operator’s central control center if an attempt to relight the pilot flame is unsuccessful.

(13) *New facility* means an oil and natural gas production facility that commenced construction on or after [**INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER**].

(14) *Oil and natural gas production facility* means a stationary source engaged in the extraction and production of oil and natural gas, including wells and all related processes used in the extraction, production, recovery, lifting, stabilization, and separation or treatment of oil and/or natural gas (including condensate), as well as the processing, storage, and upstream and midstream pipeline gathering of oil and natural gas. Oil and natural gas production components may include: wells and related casing head; tubing head and "Christmas tree'' piping; pumps; compressors; heater treaters; separators; storage vessels; pneumatic devices; natural gas glycol dehydrators; well drilling, completion and workover processes and portable non-self-propelled apparatuses associated with those operations; and low to medium pressure, smaller diameter, gathering pipelines and related components that collect and transport the oil, natural gas and other materials and wastes from the wells or well pads to the point of custody transfer to the gas plant or petroleum refinery.

(15) *Oil and natural gas well* means a single well that extracts subsurface reservoir fluids containing a mixture of oil, natural gas, and water.

(16) *Owner or operator* means any person who owns, leases, operates, controls, or supervises an oil and natural gas production facility.

(17) *Pneumatic controller* means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

(18) *Pneumatic pump* means a chemical or methanol injection or circulation pump or a diaphragm pump powered by pressurized natural gas.

(19) *Pneumatic pump emissions* means the VOC-containing emissions from natural gas-driven pneumatic pumps.

(20) *Produced natural gas* means natural gas that is separated from extracted reservoir fluids during oil and natural gas production operations.

(21) *Produced water* means water that is separated from extracted reservoir fluids during production operations.

(22) *Regional Administrator* means the Regional Administrator of EPA Region 8 or an authorized representative of the Regional Administrator of EPA Region 8 except to the extent specifically specified otherwise in a Delegation of Authority Agreement between the Regional Administrator and the Ute Indian Tribe.

(23) *Standing and breathing losses* means VOC emissions from fixed roof tanks as a result of evaporative losses during storage.

(24) *Storage tank* means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of non-earthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support.

(25) *Supervisory Control and Data Acquisition (SCADA) system* generally refers to industrial control computer systems that monitor and control industrial infrastructure or facility-based processes.

(26) *Unsafe to repair* means (in the context of fugitive emissions monitoring) that operator personnel would be exposed to an imminent or potential danger as a consequence of the attempt to repair the leak.

(27) *Utility flare* means a thermal oxidation system using an open (without enclosure) flame that is designed and operated in accordance with the requirements of 40 CFR 60.18(b). An enclosed combustor is not considered a utility flare. A combustion device is not considered a utility flare when installed horizontally or vertically within an open pit and often used in oil and natural gas production operations to combust produced natural gas during initial well completion or temporarily during emergencies when enclosed combustors or utility flares installed at a facility are not operational or injection of recovered produced natural gas is unavailable.

(28) *Visible smoke emissions* mean air pollution generated by thermal oxidation in a flare or enclosed combustor and occurring immediately downstream of the flame present in those units. Visible smoke occurring within, but not downstream of, the flame, does constitute visible smoke emissions.

(29) *Working losses* means natural gas emissions from fixed roof tanks resulting from evaporative losses during filling and emptying operations.

(c) *Requirement for testing*. The Regional Administrator may require that an owner or operator of an affected oil and natural gas production facility demonstrate compliance with the requirements of the §§ 49.4169 through 49.4183 by performing a source test and submitting the test results to the Regional Administrator. Nothing in §§ 49.4169 through 49.4183 limits the authority of the Regional Administrator to require, in an information request pursuant to section 114 of the Act, an owner or operator of an oil and natural gas production facility subject to §§ 49.4169 through 49.4183 to demonstrate compliance by performing testing, even where the facility does not have a permit to construct or a permit to operate.

(d) *Requirement for monitoring, recordkeeping, and reporting*. Nothing in §§ 49.4169 through 49.4183 precludes the Regional Administrator from requiring monitoring, recordkeeping and reporting, including monitoring, recordkeeping and reporting in addition to that already required by an applicable requirement, in a permit to construct or permit to operate in order to ensure compliance.

(e) *Credible evidence*. For the purposes of submitting reports or establishing whether an owner or operator of an oil and natural gas production facility has violated or is in violation of any requirement, nothing in §§ 49.4169 through 49.4183 precludes the use, including the exclusive use, of any credible evidence or information, relevant to whether a facility would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed.

§ 49.4172 Storage Tank VOC Emission Control Requirements.

(a) *Applicability*. The VOC emissions control requirements of this section apply to each crude oil, condensate, and/or produced water storage tank located at an affected oil and natural gas production facility as identified in § 49.4169(b), where the aggregate uncontrolled VOC emissions from all storage tanks, glycol dehydrators, and pneumatic pumps at the facility are equal to or greater than 4 tpy, as calculated using a generally accepted model or calculation methodology and based on the average monthly throughput for the facility.

(b) *VOC emission control requirements*. For each storage tank, you must comply with the VOC emissions control requirements of paragraphs (1) or (2) of this section.

(1) You must reduce VOC emissions from each storage tank by at least 95.0 percent on a continuous basis according to paragraphs (b)(1)(i)(A) or (B) of this section.

(i) You must route all flashing, working, standing and breathing losses from the crude oil, condensate, and/or produced water storage tanks through a closed-vent system that meets the conditions specified in § 49.4175(c) to:

(A) An operating system designed to recover and inject 100 percent of the natural gas emissions into a natural gas gathering pipeline system for sale or other beneficial purpose; or

(B) An enclosed combustor or utility flare designed to reduce the mass content of VOC in the natural gas emissions vented to the device by at least 98.0 percent and operated as specified in §§ 49.4175(c) and 49.4176; or

(2) You must maintain the aggregate uncontrolled VOC emissions from all storage tanks, glycol dehydrators, and pneumatic pumps at an affected oil and natural gas production facility at less than 4 tpy. Before using the uncontrolled VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled VOC emissions must be calculated using a generally accepted model or calculation methodology. Monthly calculations must be based on the average throughput of the facility for the month. Monthly calculations must be separated by at least 14 days. You must comply with paragraph (b)(1) of this section within 30 days of the monthly emissions determination required in this section if the determination indicates that VOC emissions from the aggregate of all storage tanks, glycol dehydrators, and pneumatic pumps at your affected oil and natural gas production increased to 4 tpy or greater.

(3) Except as provided in paragraph (b)(4) of this section, if you use a control device to reduce emissions from your storage tanks, you must equip each storage tank with a cover that meets the requirements of § 49.4175(b).

(4) If you use a floating roof to reduce emissions, you must meet the requirements of § 60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

§ 49.4173 Dehydrators VOC Emission Control Requirements.

(a) *Applicability*. The VOC emissions control requirements of this section apply to each natural gas glycol dehydration unit located at an affected oil and natural gas production facility as identified in § 49.4169(b) where the aggregate uncontrolled VOC emissions from all storage tanks, glycol dehydrators, and pneumatic pumps at the facility is equal to or greater than 4 tpy.

(b) *Emission control requirements*. For each glycol dehydration unit, you must comply with the VOC emissions control requirements of paragraphs (1) or (2) of this section.

(1) You must reduce VOC emissions from each glycol dehydration unit process vent by at least 95.0 percent on a continuous basis according to paragraphs (b)(1)(i)(A) or (B) of this section.

(i) You must route all glycol dehydration unit process vent emissions through a closed-vent system that meets the conditions specified in § 49.4175(c) to:

(A) An operating system designed to recover the emissions and recycle them for use in a process unit or incorporate them into a product; or

(B) An enclosed combustor or utility flare designed to reduce the mass content of VOC in the emissions vented to the device by at least 98.0 percent and operated as specified in §§ 49.4175(c) and 49.4177.

(ii) If you are complying with the requirements of this section by complying with paragraph (b)(1)(i)(A), if recycling and reusing all or part of the emissions collected in an operating system designed to recover the emissions becomes temporarily infeasible, you must route the emissions that cannot be recovered through a closed-vent system to an enclosed combustor or utility flare operated as specified in §§ 49.4175(c) and 49.4176; or

(2) You must maintain the aggregate uncontrolled VOC emissions from all storage tanks, glycol dehydrators, and pneumatic pumps at an affected oil and natural gas production facility at less than 4 tpy for 12 consecutive months in accordance with the procedures specified in § 49.4172(b)(2).

§ 49.4174 Pneumatic Pumps VOC Emission Control Requirements.

(a) *Applicability*. The requirements of this section apply to each pneumatic pump located at an affected oil and natural gas production facility as identified in § 49.4169(b) where the aggregate uncontrolled VOC emissions from all storage tanks, glycol dehydrators, and pneumatic pumps at the facility is equal to or greater than 4 tpy.

(b) *VOC Emission Control Requirements*. For each pneumatic pump, you must comply with the VOC emissions control requirements of paragraphs (1) or (2) of this section.

(1) You must reduce VOC emissions from each pneumatic pump by at least 95.0 percent on a continuous basis according to paragraphs (b)(1)(i)(A) or (B) of this section

(i) You must route all pneumatic pump emissions through a closed-vent system that meets the conditions specified in § 49.4175(c) to:

(A) An operating system designed to recover and inject the natural gas emissions into a natural gas gathering pipeline system for sale or other beneficial purpose; or

(B) An enclosed combustor or utility flare designed to reduce the mass content of VOC in the emissions vented to the device by at least 98.0 percent and operated as specified in §§ 49.4175(c) and 49.4177; or

(2) You must maintain the aggregate uncontrolled VOC emissions from all storage tanks, glycol dehydrators, and pneumatic pumps at an affected oil and natural gas production facility at less than 4 tpy for any 12 consecutive months in accordance with the procedures specified in § 49.4172(b)(2).

§ 49.4175 Covers and Closed Vent System VOC Emission Control Requirements.

(a) *Applicability*. The VOC emission control requirements in this section apply to each covers and closed vent system located at an affected oil and natural gas production facility as identified in § 49.4169(b).

(b) *Covers*. Each owner or operator must equip all openings on each crude oil, condensate, and/or produced water storage tank with a cover to ensure that all flashing, working, standing and breathing emissions are routed through a closed-vent system to a vapor recovery system, an enclosed combustor, or a utility flare.

(1) Each cover and all openings on the cover (e.g., access hatches, sampling ports, pressure relief valves (PRV), and gauge wells) must form a continuous impermeable barrier over the entire surface area of the crude oil, condensate, and/or produced water in the storage tank.

(2) Each cover opening must be secured in a closed, sealed position (e.g., covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except when it is necessary to use an opening as follows:

(i) To add fluids to, or remove fluids from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the fluids in the unit; or

(iii) To inspect, maintain, repair, or replace equipment located inside the unit.

(3) Each thief hatch cover must be weighted and properly seated to ensure that flashing, working, standing and breathing emissions are routed through the closed-vent system to the vapor recovery system, the enclosed combustor, or the utility flare under normal operating conditions.

(4) Each PRV must be set to release at a pressure that will ensure that flashing, working, standing and breathing emissions are routed through the closed-vent system to the vapor

recovery system, the enclosed combustor, or the utility flare under normal operating conditions.

(c) *Closed vent systems*. Each owner or operator must meet the following requirements for closed vent systems:

(1) Each closed vent system must route all captured storage tank flashing, working, standing and breathing losses, glycol dehydration unit process vent emissions, and pneumatic pump emissions from the affected oil and natural gas production facility to a gathering pipeline system for sale, use in a process unit, incorporation into a product, or other beneficial purpose, or to a VOC emission control device, as specified in §§ 49.4172, 49.4173, and 49.4174.

(2) All vent lines, connections, fittings, valves, relief valves, or any other appurtenance employed to contain and collect captured storage tank flashing, working, standing and breathing losses, glycol dehydration unit process vent emissions, and pneumatic pump emissions to transport such emissions to a gathering pipeline system for sale, use in a process unit, incorporation into a product, or other beneficial purpose, or to a VOC emission control device, as specified in §§ 49.4172, 49.4173, and 49.4174, must be maintained and operated properly at all times.

(3) Each closed-vent system must be designed to operate with no detectable emissions, as demonstrated by the fugitive emissions component monitoring requirements in § 49.4177(b).

(4) If any closed-vent system contains one or more bypass devices that could be used to divert all or a portion of the captured storage tank flashing, working, standing and breathing losses, glycol dehydration unit process vent emissions, and pneumatic pump emissions, from entering a gathering pipeline system for sale, use in a process unit, incorporation into a product, or other beneficial purpose, or from being transferred to the VOC emission control device, the owner or operator must meet one of the requirements in paragraphs (i) or (ii) for each bypass device. Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements applicable to bypass devices:

(i) At the inlet to such a bypass device the owner or operator must properly install, calibrate, maintain, and operate a flow indicator that is capable of taking continuous readings and sounding an alarm when the bypass device is open such that emissions are being, or could be, diverted away from a gathering pipeline system for sale, use in a process unit, incorporation into a product, or other beneficial purpose, or the VOC emission control device and into the atmosphere; or

(ii) The owner or operator must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(iii).

§ 49.4176 VOC Emission Control Devices.

(a) Applicability. The requirements in this section apply to all utility flares and enclosed combustors used to control VOC emissions at an affected oil and natural gas production facility as identified in § 49.4169(b).

(b) *Enclosed combustors and utility flares*. Each owner or operator must meet the following requirements for enclosed combustors and utility flares:

(1) For each enclosed combustor or utility flare, the owner or operator must follow the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions;

(2) The owner or operator must ensure that each enclosed combustor or utility flare is designed to have sufficient capacity to reduce the mass content of VOC in the captured emissions routed to it by at least 98.0 percent for the minimum and maximum natural gas volumetric flow rate and BTU content routed to the device;

(3) Each enclosed combustor or utility flare must be operated to reduce the mass content of VOC in the captured emissions routed to it by continuously meeting at least 95.0 percent VOC control efficiency, and must be designed and operated to achieve at least 98.0 percent VOC control efficiency on average;

(4) The owner or operator must ensure that each utility flare is designed and operated in accordance with the requirements of 40 CFR 60.18(b) for such flares;

(5) The owner or operator must ensure that each enclosed combustor is:

(i) A model demonstrated by a manufacturer to meet the VOC control efficiency requirements of §§ 49.4172, 49.4173, and 49.4174 using the EPA-approved performance test procedures specified in 40 CFR Part 60, Subpart OOOO, or Subpart OOOOa, as appropriate, by the due date of the first annual report as specified in § 49.4183(b); or

(ii) Demonstrated by the owner or operator to meet the VOC control efficiency requirements of §§ 49.4172 through 49.4174 using the EPA-approved performance test procedures specified in 40 CFR Part 60, Subpart OOOO, or Subpart OOOOa, as appropriate by the due date of the first annual report as specified in § 49.4183(b); and

(6) The owner or operator must ensure that each enclosed combustor and utility flare is:

(i) Operated properly at all times that captured emissions are routed to it;

(ii) Operated with a liquid knock-out system to collect any condensable vapors (to prevent liquids from going through the control device);

(iii) Equipped with a flash-back flame arrestor;

(iv) Equipped with a continuous burning pilot flame and an operational electronically controlled automatic ignition device with a malfunction alarm and remote notification system that sounds if the pilot flame fails while captured emissions are flowing to the enclosed combustor or utility flare;

(v) Equipped with a continuous recording device, such as a chart recorder, data logger or similar device, or connected to a SCADA system, to monitor and document proper operation of the enclosed combustor or utility flare;

(vi) Maintained in a leak-free condition; and

(vii) Operated with no visible smoke emissions.

§ 49.4177 Fugitive Emissions VOC Emission Control Requirements.

(a) Applicability. The requirements of this section apply to all owners or operators of the collection of fugitive emission components, as defined in § 49.4171, at an affected oil and natural gas production facility as identified in § 49.4169(b), where facility-wide actual VOC emissions are greater than or equal to 5 tpy.

(b) Monitoring Requirements. (1) Each owner or operator must develop and implement a Reservation-wide fugitive emissions monitoring plan to reduce emissions from fugitive emissions components at all of their affected oil and natural gas production facilities on the Indian country lands within the U&O Reservation. The Reservation-wide monitoring plan must include the following elements:

(i) A requirement to perform an initial monitoring of the collection of fugitive emissions components at each affected oil and natural gas production facility by **[INSERT 18 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE];**

(ii) A requirement to perform subsequent monitoring of the collection of fugitive emissions components at each affected oil and natural gas production facility at least once every 12 months after the initial monitoring, with consecutive monitoring surveys conducted at least ten months apart;

(iii) A requirement to change monitoring frequency as follows: (A) increase monitoring frequency to once every 6 months, with consecutive surveys conducted at least 5 months apart, if 2 or more leaking fugitive emissions components are detected during any single survey; and (B) reduce monitoring frequency back to once every 12 months, if no leaks are detected during 2 consecutive semi-annual surveys;

(iv) A description of the technique used to identify leaking fugitive emission components, which must be limited to either:

(A) EPA Reference Method 21, 40 CFR Part 60, Appendix A, where an analyzer reading of 500 parts per million volume (ppmv) VOC or greater is considered a leak in need of repair; or

(B) An optical gas imaging instrument, as defined in 40 CFR 60.18(g)(4), where any visible emissions are considered a leak in need of repair, unless the owner or operator evaluates the leak with an analyzer meeting EPA Reference Method 21 at 40 CFR Part 60, Appendix A and the concentration is less than 500 ppmv. The optical gas imaging instrument must be capable of meeting the optical gas imaging equipment requirements specified in 40 CFR Part 60, subpart OOOOa;

(v) The manufacturer and model number of any fugitive emissions monitoring device to be used;

(vi) Procedures and timeframes for identifying and repairing components from which leaks are detected, including:

(A) A requirement to repair any leaks identified from components that are safe to repair and do not require facility shut down as soon as practicable, but no later than 15 calendar days after discovering the leak;

(B) Timeframes for repairing leaking components that are unsafe to repair or require facility shut down, to be no later than the next required monitoring event; and

(C) Procedures for verifying leaking component repairs;

(vii) Training and experience needed before performing surveys;

(viii) Procedures for calibration and maintenance of any fugitive emissions monitoring device to be used; and

(ix) Standard monitoring protocols for each type of typical affected oil and natural gas production facility (e.g., well site, tank battery, compressor station), including a general list of component types that will be inspected and what supporting data will be recorded (e.g., wind speed, detection method device-specific operational parameters, date, time, and duration of inspection).

(2) The owner or operator is exempt from inspecting a valve, flange, or other connection, pump or compressor, pressure relief device, process drain, open-ended valve, pump or compressor seal system degassing vent, accumulator vessel vent, agitator seal, or access door seal under any of the following circumstances:

(i) The contacting process stream only contains glycol, amine, methanol, or produced water;

(ii) If using Method 21, the monitoring could not occur without elevating the monitoring personnel to an immediate danger as a consequence of completing monitoring;

(iii) Monitoring could not occur without exposing monitoring personnel to an immediate danger as a consequence of completing monitoring; or

(iv) The item to be inspected is buried, insulated in a manner that prevents access to the components by a monitor probe or optical gas imaging device, or obstructed by equipment or piping that prevents access to the components by a monitor probe or optical gas imaging device.

§ 49.4178 Tank Truck Loading VOC Emission Control Requirements

(a) *Applicability*. The requirements in this section apply to each owner or operator who loads or permits the loading of any intermediate hydrocarbon liquid or produced water at an affected oil and natural gas production facility as identified in § 49.4169(b)(2).

(b) *Tank Truck Loading Requirements*. Tank trucks used for transporting intermediate hydrocarbon liquid or produced water must be loaded using bottom filling or a submerged pipe.

§ 49.4179 Pneumatic Controllers VOC Emission Control Requirements.

(a) *Applicability*. (1) The VOC emission control requirements in this section apply to each owner or operator of any existing pneumatic controller located at an affected oil and natural gas production facility as identified in § 49.4169(b)(2).

(b) *Retrofit Requirements*. (1) All existing pneumatic controllers must meet the standards established for pneumatic controllers that are constructed, modified, or reconstructed on or after October 15, 2013, as specified in 40 CFR Part 60, Subpart OOOO Standards of

Performance for Crude Oil and Natural Gas Production, Transmission and Distribution.

(c) *Documentation Requirements.* The owner or operator of any existing pneumatic controllers must meet the tagging requirements in 40 CFR 60.5390(b)(2) and 40 CFR 60.5390(c)(2), except that the month and year of installation, reconstruction or modification is not required.

§ 49.4180 Other combustion devices.

(a) *Applicability.* (1) The VOC emission control requirements in this section apply to each owner or operator of any existing enclosed combustor, utility flare, or other flare located at an affected oil and natural gas production facility as identified in § 49.4169(b)(2) that is used to control VOC emissions, but is not required under §§ 49.4172, 49.4173, 49.4174, and 49.4176 of this rule.

(b) *Retrofit Requirements.* (1) All existing enclosed combustors, utility flares, or other open flares must be equipped with an operational electronically controlled automatic ignition device.

§ 49.4181 Monitoring requirements.

(a) For each affected oil and natural gas production facility as identified in § 49.4169(b):

(1) Each owner or operator must measure the barrels of crude oil, condensate, and produced water produced at the oil and natural gas production facility each time the liquids are unloaded from the storage tanks using process flow meters and/or sales records.

(2) Each owner or operator must perform quarterly auditory, visual, olfactory (AVO) inspections of tank thief hatches, covers, seals, pressure relief valves, and closed vent systems to ensure proper condition and functioning. The quarterly inspections must be performed while the crude oil, condensate, and produced water storage tanks are being filled. If any of the components are not in good working condition, they must be repaired within 15 days of identification of the deficient condition.

(3) Each owner or operator must perform quarterly visual inspections of the peak pressure and vacuum values in each closed vent system and control device system to ensure that the pressure and vacuum relief set points are not being exceeded in a way that has resulted, or might result, in venting and possible damage to equipment. The quarterly inspections must be performed while the crude oil, condensate, and produced water storage tanks are being filled.

(4) Each owner or operator must monitor the operation of each enclosed combustor and utility flare to confirm proper operation and demonstrate compliance with the VOC control efficiency requirements of §§ 49.4172 through 49.4174 as follows:

(i) Continuously monitor the enclosed combustor and utility flare operation, using a malfunction alarm and remote notification system for failures, and checking the system for proper operation whenever an operator is on site, at least quarterly;

(ii) Continuously monitor all variable operational parameters specified in the manufacturer's written operating instructions and procedures;

(iii) Using EPA Reference Method 22 of 40 CFR part 60, Appendix A, confirm at least once per calendar quarter that no visible smoke emissions are present, except for periods not to exceed a total of 2 minutes during any hour, during operation of any enclosed combustor and utility flare. The observation period must be 15 minutes; and

(iv) Respond to any observation of improper monitoring equipment operation or any alarm of pilot flame failure and ensure that monitoring equipment is returned to proper operation and/or the pilot flame is relit as soon as practically and safely possible after an observation or an alarm sounds

(5) Where sufficient to meet the monitoring requirements in this section, the owner or operator may use a SCADA system to monitor and record the required data in paragraphs (a)(1) through (4).

§ 49.4182 Recordkeeping requirements.

(a) Each owner or operator of an affected oil and natural gas production operation as identified in section 49.4169(b) must maintain the following records, as applicable:

(1) For each affected oil and natural gas production facility as identified in § 49.4169(b):

(i) The measured barrels of crude oil, condensate, and produced water produced at the oil and natural gas production facility each time the liquids are unloaded from the storage tanks;

(ii) As applicable, the monthly calculations demonstrating that the uncontrolled actual VOC emissions from the aggregate of all storage tanks, glycol dehydrators, and pneumatic pumps at an affected oil and natural gas production facility as identified in § 49.4169(b) has been maintained at less than 4 tpy;

(iii) For each enclosed combustor or utility flare at an affected oil and natural gas production facility required under §§ 49.4172 through 49.4176:

(A) Manufacturer-written, site-specific designs, operating instructions, operating procedures and maintenance schedules, including those of any operation monitoring systems;

(B) Date of installation;

(C) Records of all required monitoring of operations in §49.4181;

(D) Records of any deviations from the operating parameters specified by the written site-specific designs, operating instructions, and operating procedures. The records must include: the enclosed combustor or utility flare's total operating time during which a deviation occurred; the date, time and length of time that deviations occurred; the corrective actions taken; and any preventative measures adopted to operate the device within that operating parameter;

(E) Records of any instances in which the pilot flame is not present or the monitoring equipment is not functioning in the enclosed combustor or utility flare, the date and times of the occurrence, the corrective actions taken, and any preventative measures adopted to prevent recurrence of the occurrence;

(F) Records of any instances in which a recording device installed to record data from the enclosed combustor or utility flare is not operational; and

(G) Records of any time periods in which visible smoke emissions are observed emanating from the enclosed combustor or utility flare. (iv) For each closed-vent system: (A) The date of installation; and (B) Records of any instances in which any closed-vent system or control device was bypassed or down, the reason for each incident, its duration, and the corrective actions taken and any preventative measures adopted to avoid such bypasses or downtimes; and

(v) Documentation of all storage tank and closed vent system inspections required in §§ 49.4181(e) and (f) All inspection records must include the following information:

(A) The date of the inspection;

(B) The findings of the inspection;

(C) Any adjustments or repairs made as a result of the inspection, and the date of the adjustment or repair; and

(D) The inspector's name and signature;

(vi) The Uinta Basin-wide fugitive emissions monitoring plan for the Indian country lands portion of the U&O Reservation; and

(vii) Documentation of each fugitive emissions inspection at all affected oil and natural gas production operations. All inspection records must include the following information:

(A) The date of the inspection;

(B) The identification of any component that was determined to be leaking;

(C) The identification of any component not exempt under § 49.4177(b)(2) that is not inspected and the reason it was not inspected;

(D) The date of the first attempt to repair the leaking component;

(E) The identification of any component with a delayed repair and the reason for the delayed repair: (*I*) For unavailable parts: (*A*) The date of ordering a replacement component; and (*B*) The date the replacement component was received; and (*II*) For a shutdown: (*A*) The reason the repair is technically infeasible; (*B*) The date of the shutdown; (*C*) The date of subsequent startup after a shutdown; and (*D*) Emission estimates of the shutdown and the repair if the delay is longer than 6 months;

(F) The date and description of any corrective action taken, including the date the component was verified to no longer be leaking;

(G) The identification of each component exempt under § 49.4177(b)(2), including the type of component and a description of the qualifying exemption; and

(H) The inspector's name and signature.

(2) For each affected oil and natural gas production facility as identified in § 49.4169(b)(2):

(i) For each electronically controlled automatic ignition system required under § 49.4180, records demonstrating the date of installation and manufacturer specifications;

(ii) For each retrofitted pneumatic controller, the records required in 40 CFR 60.5420(c)(4)(i); and

(3) The actual VOC emissions for the facility for each consecutive 12-month period and documentation supporting the emissions calculations for each VOC-emitting unit or activity.

(b) Each owner or operator must keep all records required by this section onsite at the facility or at the location that has day-to-day operational control over the facility and must make the records available to the EPA upon request.

(c) Each owner or operator must retain all records required by this section for a period of at least five years from the date the record was created.

§ 49.4183 Notification and Reporting Requirements.

(a) Each owner or operator must submit any documents required under this rule to: U.S. EPA Region 8, Office of Enforcement, Compliance & Environmental Justice, Air Toxics and Technical Enforcement Program, 8ENF-AT, 1595 Wynkoop St., Denver, CO 80202, or documents may be submitted electronically to **r8airenforcementreports@epa.gov**.

(b) Each owner and operator must submit an annual report containing the information specified in paragraphs (b)(1) through (3) of this section. The annual report must cover the period for the previous calendar year. The initial annual report is due within 90 days after 1 year after **[INSERT 30 DAYS AFTER DATE OF PUBLICATION OF THE FINAL RULE IN THE FEDERAL REGISTER]**. Subsequent annual reports are due on the same date each year as the date the initial annual report was submitted. If you own or operate more than one affected oil and natural gas production facility, you may submit one report for multiple oil and natural gas production facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (3) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. An alternative schedule on which reports required by §§ 49.4169 through 49.4183 must be submitted will be allowed as long as the schedule does not extend the reporting period. The annual report must include:

(1) The owner or operator name, and the name and location (decimal degree latitude and longitude location indicating the datum used in parentheses) of each oil and natural gas production facility being included in the annual report.

(2) The beginning and ending dates of the reporting period.

(3) For each affected oil and natural gas production facility, the information in paragraphs (b)(3)(i) through (iii) of this section.

(i) A summary of all required records specified in § 49.4182;

(ii) The actual VOC emissions for the facility for the reporting period and documentation supporting the emissions calculations for each VOC-emitting unit or activity.

(3) Reserved §§ 49.4184 through 49.9860